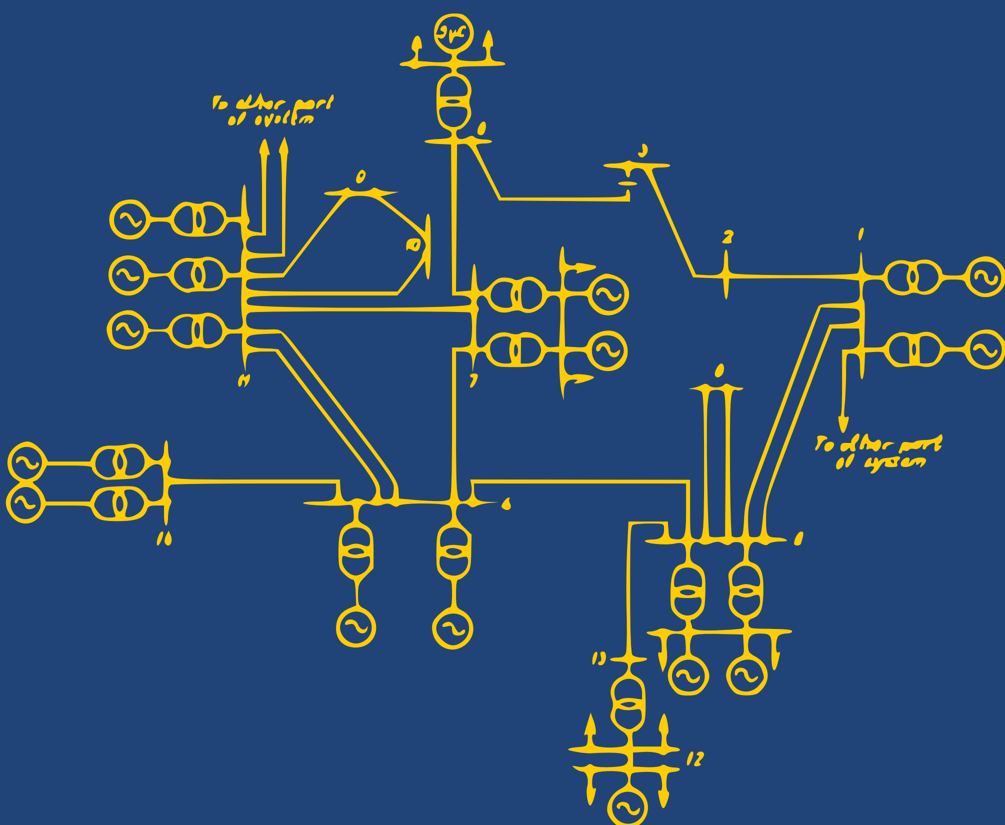
A. BARZAM

AUTOMATION IN ELECTRICAL POWER SYSTEMS



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AUTOMATION IN ELECTRICAL POWER SYSTEMS

Translated from the Russian
by
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The Greek Alphabet

Α α	Alpha	Ι ι	Iota	Ρ ρ	Rho
Β β	Beta	Κ κ	Kappa	Σ σ	Sigma
Γ γ	Gamma	Λ λ	Lambda	Τ τ	Tau
Δ δ	Delta	Μ μ	Mu	Υ υ	Upsilon
Ε ε	Epsilon	Ν ν	Nu	Φ φ	Phi
Ζ ζ	Zeta	Ξ ξ	Xi	Χ χ	Chi
Η η	Eta	Ο ο	Omicron	Ψ ψ	Psi
Θ θ ϑ	Theta	Π π	Pi	Ω ω	Omega

The Russian Alphabet and Transliteration

А а	a	К к	k	Х х	kh
Б б	b	Л л	l	Ц ц	ts
В в	v	М м	m	Ч ч	ch
Г г	g	Н н	n	Ш ш	sh
Д д	d	О о	o	Щ щ	shch
Е е	e	П п	p	Ъ ъ	”
Ё ё	ë	Р р	r	Ы ы	y
Ж ж	zh	С с	s	Ь ь	’
З з	z	Т т	t	Э э	e
И и	i	У у	u	Ю ю	yu
Й й	i	Ф ф	f	Я я	ya

На английском языке

CONTENTS

PREFACE

This is the third Russian edition of "Automation in Electrical Power Systems" which covers design and operation of automatic control devices intended to prevent and clear faults in electrical power systems and restore power to the loads in the event of breakdown thus assuring continuity of the supply.

The reliable and unfailing operation of such devices has been ensured through the research and development effort put into automatic power control systems.

The book discusses automatic control in conjunction with protective relaying, since the required reliability and economy of power system operation can be achieved through the combined action of both groups of equipment, each catering for specific aspects in functioning of loads and generating sources.

The wide use of automatic control systems adds to the reliability, stability and economy of power supply systems and takes some burden from attending personnel.

The book is designed as a study guide for students of power engineering secondary schools. It may also interest engineers concerned with the operation, installation and design of protective relaying and automatic devices used in electric power stations and networks.

PREFACE

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Introduction

I-1. Purpose of Automatic Power Control Systems

For the purpose of this book, the term "automatic control systems" will apply to an assemblage of devices which are not protective relays, although interacting with them and performing operations in order to:

prevent, locate and eliminate faults affecting the whole or part of a power system;

distribute electric power to the individual parts of a power system;

restore normal connections in the system and the continuity of power supply to loads after faults.

Early devices of this type appeared in Soviet power systems even in the thirties including automatic transfer equipment, automatic circuit reclosers and automatic forcing devices for excitation of generators. About the same time, work closely related to the above mentioned automatic control systems was started to find ways and means of preventing false operation of relays under overloads and instabilities, and to use the self-starting ability of induction motors.

When used on a large scale in the Ural power systems, these practices fully proved their worth under the strain of the Great Patriotic war in 1942-1945. As a result, there were practically none of the severe instabilities, sustained loss of synchronism or heavy load shedding which occurred in the past.

It is of interest to note that at that and later time the devices used in the Urals to sectionalize the power system at will upon a loss of synchronism were classed with protective relaying and called accordingly "sectionalizing protections". Today similar devices are looked upon as vital automatic control system components and are usually termed "sectionalizing controls".

The successful experience gained from the use of automatic power controls employed in the Ural power system was utilized and developed in the Central power systems, Leningrad power system and later on in other regional power systems of the USSR.

At that time, important additions were made to the automatic control equipment in the form of automatic frequency control. Techniques have been developed which assure reversal of synchronous motors and quick connection of synchronous generators through the self-synchronization method under emergency conditions. With the generating units at hydro-electric power sta-

tions put under automatic control, automatic devices have come into use which activate the reserve capacity upon a reduction in the frequency.

Automatic reclosure equipment was extended to include phase-by-phase and some other varieties of reclosure not only on power transmission lines, but also on busbars and transformers. Improvements have been made in both the circuitry and components of power control systems and new automatic devices have appeared. All this materially contributed to the creation of the Unified Power Grid of the European USSR and its trouble-free operation.

According to the Regulations for Installation of Electrical Equipment, the devices comprising automatic power control systems must be considered at the design stage and put into service at newly built power systems. The latest edition of these regulations (1966) includes a section "Automatic Control Systems" which covers automatic reclosure; automatic transfer; generator control; automatic regulation of excitation, voltage and reactive power; automatic frequency control of power system; automatic regulation of frequency and active power; sectionalizing protection.

Automatic control devices may be referred to any particular category only arbitrarily, because one and the same device can produce many effects. For example, instantaneous clearing of short-circuits adds to the stability of parallel operation of synchronous machines, facilitates self-starting of asynchronous loads, reduces resulting damage and improves the probability of successful automatic reclosure, i.e., contributes to the quick restoration of the normal power system operation. Another example is the effective use of automatic transfer devices in the house circuits. Those devices, when combined with appropriate sectionalizing technique, do not allow single shutdowns or faults to grow into a major station outage which may well expand into a system outage.

There is a close functional tie-in between devices which automatically regulate frequency and active power, control and limit power flows in transmission lines, unload the lines, and the automatic sectionalizing devices.

Where systems are only loosely interconnected, parallel operation can be ensured and the power-carrying capacity of the interconnections can be better utilized only through the combined use of the above devices.

Devices used for automatic excitation regulation of synchronous machines improve the stability of parallel operation, add to the performance accuracy of protective relaying, facilitate the self-starting of loads after clearing short-circuit faults and allow the voltage regulation process to be performed automatically.

In some cases, automatic transfer and reclosure equipment can give a sufficient degree of operational stability to simplified substations using inexpensive switchgear.

Supervisory control of a power system finds its use along with power system automation. The remote control, telemetering and remote signalling (supervisory control) devices allow the monitoring and control of remote stations or units to be centralized by transmitting the required information over a distance, which in turn makes it possible for the power system or its part to have centralized control. Control operations in this event are performed directly by person-

nel at the central station. Such supervisory control is far from being automatic. It is planned to make supervisory control fully automatic by using high-speed digital and analog electronic computers.

It should be noted that if an operation can be performed automatically or manually by supervisory control with much the same technical and economic results preference should be given to automation. In this event, possible errors of operators are prevented, their work is made easier, and reliability is improved.

Supervisory control lies beyond the scope of this book, as it is a subject in its own right. The only exception is remote tripping, for remote tripping devices are purposely designed to operate in conjunction with protective relaying and automatic control devices. Devices for remote automatic centralized regulation including telemetering and remote control apparatus are not considered either as they are still under development.

I-2. Elements of Automatic Control Systems

Any automatic control device including those used in power systems has in one form or another the following essentials: an element to sense the effect of an external factor, an element to convert it into an output signal in a predetermined manner, and an element which carries into effect the action of the output signal so that the variable may be under control. These elements may use combinations of devices performing amplification, signal delay, logical and mathematical operations (summation, inversion, differentiation, integration, multiplication, division), and also transducers, relays and regulators or controllers.

Transducers or measuring elements respond to an external action. When converting this action into an output signal, a transducer may operate intermittently or continuously, as appropriate to the control action adopted.

A *relay* is a device designed to interpret an input value characteristic of certain external phenomena in order to automatically change in a stepwise manner another value determining another external phenomenon.

An automatic *controller* (regulator) is a device which maintains a desired quantity at a predetermined value or varies it according to a predetermined plan or according to a self-executed plan satisfying the specified, say, optimum, conditions of operation.

Although they may sometimes act independently of one another, automatic control devices and their elements are usually coupled electrically, magnetically, mechanically, hydraulically or pneumatically to each other or to elements essential to the operation of the entire *automatic system.*

Electrical interconnections of the individual elements of automatic devices and various automatic systems are depicted in the form of diagrams.

Circuit diagrams are drawn and circuit symbols are used in accordance with pertinent State Standards[I-1].

High standards of reliability are an important requirement generally placed upon automatic control devices. Lately, it has become possible to regard relia-

bility as a measurable performance parameter and on this basis to better predict the reliability of various designs.

The failure rate of automatic control devices is given by the total number of element failures during a given service life. Service conditions are supposed to be invariable during the entire service period. Failure occurrence is dependent on the compound action of a number of statistical random processes acting during time *t*.

The failures as defined above with continuously acting automatic control systems including regulators (controllers) show themselves immediately as faults in the proper operation of the system being controlled. With discrete-action automatic devices, automatic circuit reclosing, automatic frequency control, and automatic sectionalizing devices, for instance, a failure may manifest itself either as an inability to operate or as an unnecessary functioning operation. Under adverse conditions both types of failure may result in a power system breakdown or may lead to its development.

It is possible to specify the probability of no-failure operation, P_t, that the control system and its elements should have. It, thus, appears necessary, by the reliability theory, to resort to the system and element redundancy.

It is important to make the system convenient to operate and maintain so that no check or test can interfere with the functioning of the basic equipment.

With a discrete-action automatic control device the probability of no-failure operation during a waiting period (*queuing time*) P_{tw} should be at least 0.9 to 0.95, these figures being based on the performance analysis of similar devices in use. During holding (*service time*), i.e., when a need arises for device functioning, the P_t value should be 0.95 to 0.99. With continuous-action automatic control devices (regulators) the probability of no-failure operation must evidently be not less than 0.9[I-2].

The greater the non-failure probability, the more dependable the device and, hence, the more rarely it may be subjected to scheduled maintenance.

Probability of no-failure operation P_t, as a function of mean time t to failure, and failure rate λ is defined by the exponential reliability equation:

$$P_t = e^{-\lambda t} \tag{I-1}$$

The above expression is valid for most devices in mass use for which the failure rate λ remains constant over the time t under consideration.

With devices whose compound action is determined by series connection of its elements or by their sequential functioning, the total failure rate

$$\lambda_\Sigma = \lambda_1 + \lambda_2 + \lambda_3 + \ldots + \lambda_n \tag{I-2}$$

and

$$P_{\Sigma t} = p_1 p_2 p_3 \ldots p_n \tag{I-3}$$

With devices the compound action of which is determined by parallel connection of its elements or their parallel operation (an example is parallel redundancy components), the exponential reliability equation cannot be used. If this is so, the failure probability Q of a system including n parallel-connected

elements

$$Q_{\Sigma t} = q_1 q_2 q_3 \ldots q_n \tag{I-4}$$

The compound probability of no-failure operation becomes

$$P_{\Sigma t} = 1 - Q_{\Sigma t} \tag{I-5}$$

as

$$P_{\Sigma \gamma} + Q_{\Sigma t} = 1 \tag{I-6}$$

For conservative calculations of a reliability margin, as compared to the actual value of failure rate, λ_Σ may be approximately estimated similarly to the total resistance of parallel-connected electrical networks

$$\frac{1}{R_\Sigma} = \frac{1}{r_1} + \frac{1}{r_2} + \frac{1}{r_3} + \ldots + \frac{1}{r_n} \tag{I-7}$$

i.e.

$$\frac{1}{\lambda_\Sigma} = \frac{1}{\lambda_1} + \frac{1}{\lambda_2} + \frac{1}{\lambda_3} + \ldots + \frac{1}{\lambda_n} \tag{I-8}$$

Automatic control equipment must be chosen with a particular objective in view. In some simple cases, the choice may be based on the economic gain returned by the use of such equipment. Examples are automatic circuit reclosures for a single line with one-end supply, automatic transfer operations at a two-transformer step-down substation with separate operation of the transformers at the low-tension side, automatic regulation of the voltage across step-down transformers under load, automatic regulation of power flows, etc. In such cases, the performance and economic characteristics obtained are determined by comparing the savings of the automated and non-automated systems after a year's operation

$$P_e = (P_{aut} - 1.16 P_{ex}) - P_{non\text{-}aut} \tag{I-9}$$

where P_{aut} = economic characteristics per operation year of many units in an automated system

P_{ex} = total annual expenditure required for placing the automatic system into service and for its operation and maintenance. The depreciation period of the equipment may be assumed to be 15 years. Therefore, the cost of equipment per year of operation may be evaluated as 1/15th of its total cost including installation and shipment costs

1.16 = national economy coefficient when P_{ex} sum of money is invested in the industry

$P_{non\text{-}aut}$ = economic characteristics per operation year of a non-automated system

However, to calculate the economic benefits, say, from equipping a power centre with all the required automatic controls is at present far from easy.

Statistical data may be used to determine the failure probability of separate elements of equipment and transmission lines. Since the use of a whole assemb-

lage of automatic power control system has now become an integral part of the power generation and distribution process in the Soviet Union, the probability of a severe chain fault affecting the entire power system is minute and can be hardly determined[I-1].

I-3. Automatic Control and Controllers

Automatic control is an integral part of most automation processes. The appropriate general theory is an individual subject. Discussed below are only some of the principles of the theory and the definitions needed for considering actual automatic controllers of the automatic power control system. A manual control process is considered first.

For example, the terminal voltage of a generator starter has deviated from the rated value. Observing this on an instrument, the operator begins to decrease or increase the resistance of the exciter field rheostat, depending on whether the voltage has increased or decreased until the generator stator terminal voltage returns to its rated value.

Now, let us answer the following question: at what voltage deviation must the operator operate the exciter field rheostat and at what rate?

If control adjustments are begun at very small departures with perceptible changes in the field rheostat resistance overshooting may occur, which may also happen if the operator starts the control operation during short-time transient voltage variations. A skilled operator begins to change the position of the field (shunt) rheostat control only after ΔU exceeds a certain permissible value during a period long enough to show that the process is not transient. The greater the voltage departure, the more quickly he will operate the control. However, to perform such actions quickly with proper coordination is not easy and the variable under control cannot be manually maintained accurate and continuous.

Automatic control (Fig. I-1) should not only remove the burden of strained attention and corresponding actions from the operator, it should also materially improve the control process and eliminate the human factor among other effects. Manual control is accomplished through an open-loop system, whereas the automatic control is performed by a close-loop system without human intervention.

With the open-loop systems of control the input, depending on the output value, is acted upon by the operator. In the case of closed-loop systems this action is carried out by the feedback device. Individual elements of a control system may also be operated on a feedback basis.

We distinguish between two basic types of feedback: degenerative or negative feedback in closed-loop control systems when the feedback energy is out of phase with the applied signal and thus opposes it, and regenerative or positive feedback when the output is in phase with the input, i.e., it reacts upon the input in such a manner as to reinforce the initial power. This latter phenomenon is applied in various types of amplifiers.

Feedback systems may be direct or elastic. Direct systems have continuous feedback signals. Elastic systems have their feedback signals fed only at discrete instants of time. The abrupt change of a variable under control during a transient process of regulation going at a certain rate is an example.

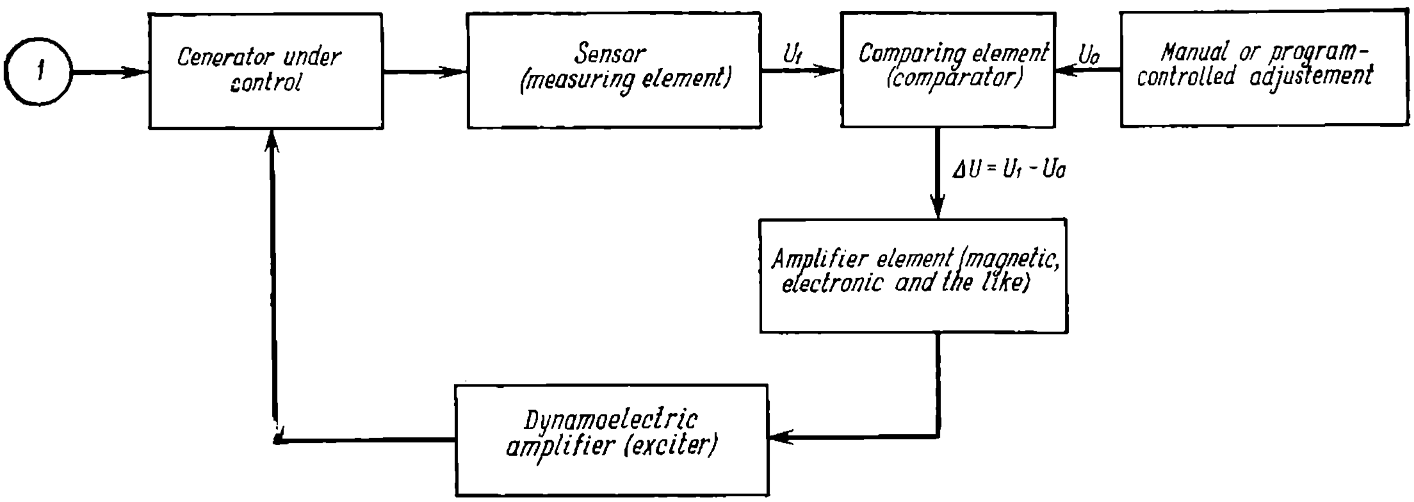


Fig. I-1. Diagram showing the voltage control across the generator stator terminals

1 — disturbing effect

By the resultant effect on the change of the variable under control the control systems are subdivided into astatic and static (Fig. I-2). Within an adequate control range, the astatic control keeps the value of the variable y constant whatever the variations of the input parameter (x)

$$y = y_{orig} = \text{const} \tag{I-10}$$

Under static control

$$y = y_{orig} - kx \tag{I-11}$$

where

$$k = \tan\alpha \tag{I-12}$$

and called "static coefficient".

For analysis, an automatic control process is divided into separate elements (Fig. I-3). The operation of each element is described by its static (steady-state) and dynamic characteristics. The *static characteristic* illustrates the relationship between the output (y) and input (x) when operating under *steady-state* conditions with external effects being varied.

An element is called linear if its static characteristic is expressed by a linear relationship.

If the element characteristic is other than linear, its properties are often analyzed by means of the linear-segment replacement method, i.e., the curved portion of the characteristic is replaced at certain intervals with straight line segments at different angles.

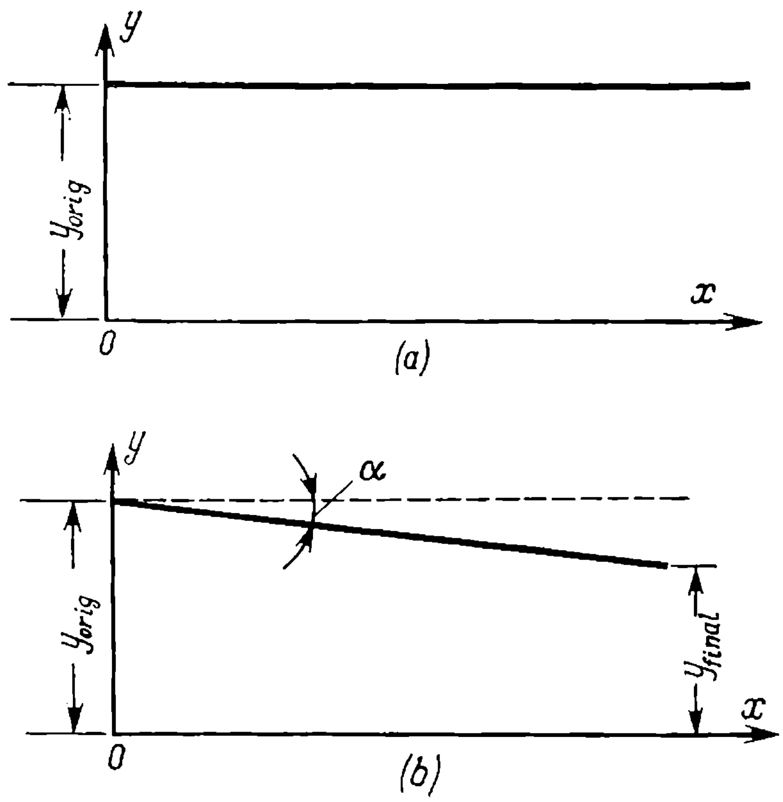


Fig. 1-2. Characteristics of control system
(*a*) astatic; (*b*) static

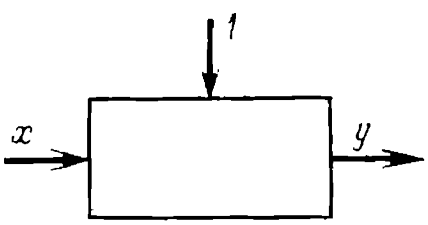


Fig. 1-3. Control system element
1 — disturbing effect

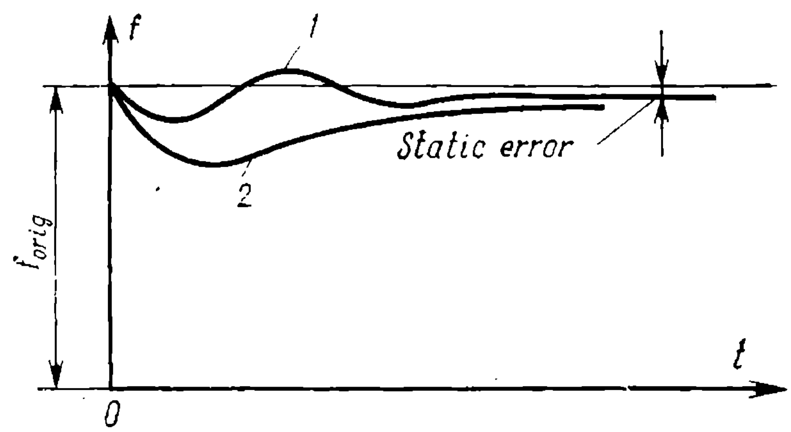


Fig. 1-4. Power system frequency changes after throwing off load and use of reserve
1 — with overshooting; *2* — without overshooting

The final steady-state output value of the element

$$y_{final} = k_g x_{final} \tag{I-13}$$

where k_g is the gain factor of the element.

If an automatic control system has 1, 2, 3, . . ., n series-connected elements with gain factors k_{g1}, k_{g2}, k_{g3}, . . ., k_{gn} respectively, the total gain factor

$$k_g = k_{g1} k_{g2} k_{g3} \ldots k_{gn} \tag{I-14}$$

The greater the control system gain factor, the more intensive is the control process, but the possibility of overshooting is greater. When use is made of automatic control, the difference between the final steady-state value of the parameter under control and its original value is determined by the value of *static error* (Fig. I-4). This error defines the static nature of the control process.

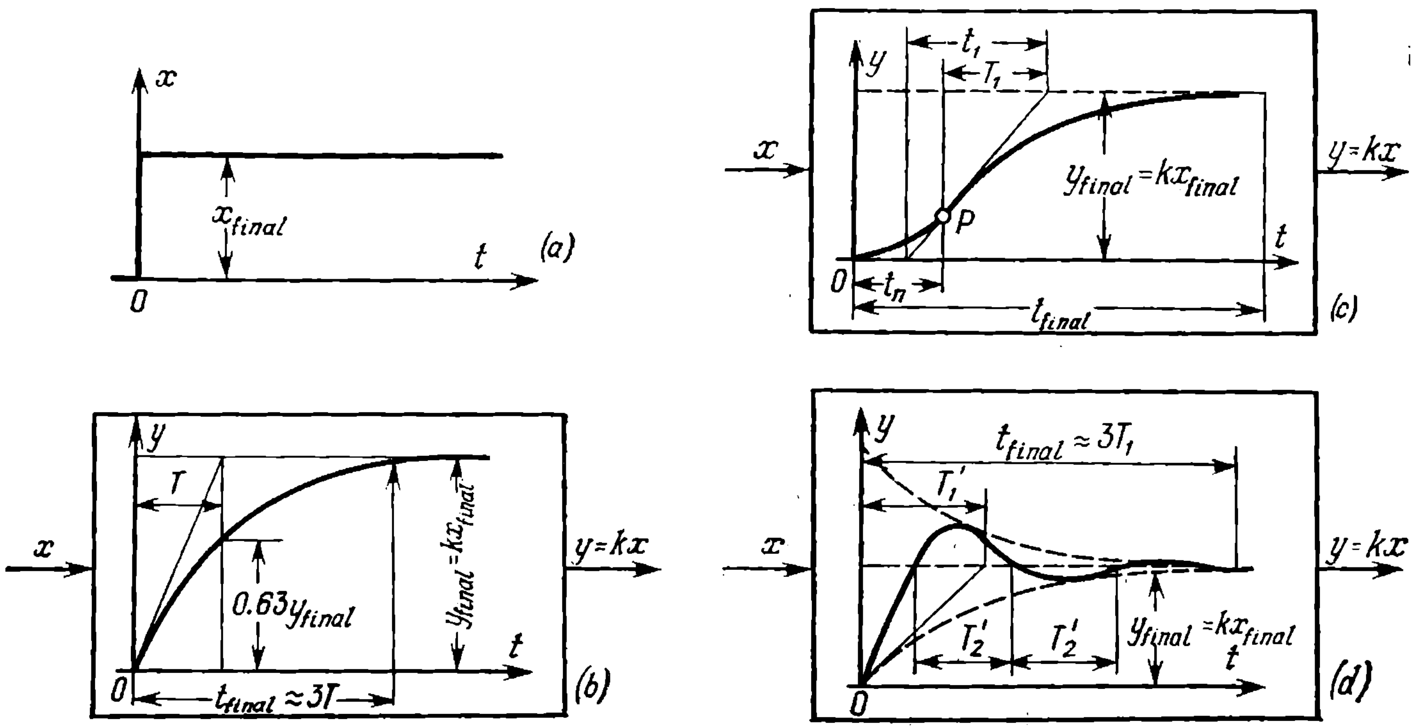


Fig. I-5. Control characteristics

(*a*) characteristic of input variable change $x = f_1(t)$; (*b*) simple lag elements; (*c*) quadratic lag element; (*d*) oscillating element

The *dynamic characteristics* is the time variation dependence of the element output parameter $y = f(t)$ after instantaneously applying an external disturbance which changes abruptly the input variable x by a certain final x_{final} value (Fig. I-5*a*).

The control elements may be distinguished by their dynamic characteristics. Some of the basic distinctions are as follows.

Simple lag element (Fig. I-5*b*). The characteristic of the element is described by the expression

$$y = y_{final}\left(1 - e^{-\frac{t}{T}}\right) \tag{I-15}$$

which is the solution of differential equation

$$T\frac{dy}{dt}+y=kx \tag{I-16}$$

The constant T found in (I-15) and (I-16) describes the time lag of the element. The final steady-state value sets in after time $t_{final} \approx 3T$.

Quadratic lag element (Fig. I-5*c*). The characteristic curve of this element has a deflection point P and is described by a second order differential equation

$$T_{\text{II}}^2\frac{d^2y}{dt^2}+T_{\text{I}}\frac{dy}{dt}+y=kx \tag{I-17}$$

when

$$T_{\text{I}} \geqslant 2T_{\text{II}} \tag{I-18}$$

Here $T_{\text{II}} = f\left(\frac{t_1}{T_1}\right)$ [see Fig. I-5*c* and reference I-4].

A quadratic lag element can be obtained by cascade connection of two simple lag elements. Let $y_1 = f_1(x_1)$ be the static characteristic of the first element and $y_2 = f_2(x_2)$ of the second element, then

$$T_1\frac{dy_1}{dt}+y_1=k_1x_1 \tag{I-19}$$

is the dynamic characteristic of the first element and

$$T_2\frac{dy_2}{dt}+y_2=k_2x_2 \tag{I-20}$$

is the dynamic characteristic of the second element. M

The resultant characteristic is found by substituting y_1 for x_2.

The resultant static characteristic is determined by the expression

$$y_2=f(x_2)=f_2[f_1(x)]=f_3(x_1) \tag{I-21}$$

The resultant dynamic characteristic is obtained as follows. From (I-20) we have

$$x_2=\frac{T_2}{k_2}\frac{dy_2}{dt}+\frac{y_2}{k_2}=y_1 \tag{I-22}$$

Substituting the value of y_1 from (I-22) into (I-19) gives

$$\left[\frac{T_1T_2}{k_2}\frac{d^2y_2}{dt^2}+\frac{T_1}{k_2}\frac{dy_2}{dt}\right]+\left[\frac{T_2}{k_2}\frac{dy_2}{dt}+\frac{y_2}{k_2}\right]=k_1x_1$$

Hence

$$\frac{T_1T_2}{k_2}\frac{d^2y_2}{dt^2}+\frac{(T_1+T_2)}{k_2}\frac{dy_2}{dt}+\frac{y_2}{k_2}=k_1x_1 \tag{I-23}$$

or

$$T_1T_2=\frac{d^2y_2}{dt^2}+(T_1+T_2)\frac{dy_2}{dt}+y_2=k_1k_2x_1 \tag{I-24}$$

which corresponds to (I-17), where

$$\left.\begin{aligned} T_1 T_2 &= T_{\mathrm{II}}^2 \\ T_1 + T_2 &= T_{\mathrm{I}} \\ k_1 k_2 &= k \end{aligned}\right\} \quad \text{(I-25)}$$

Oscillating element (Fig. I-5*d*). The oscillation amplitude fades exponentially. The characteristic is expressed by a second order differential equation

$$T_2^2 \frac{d^2y}{dt^2} + T_1 \frac{dy}{dt} + y = kx$$

when

$$T_1 < 2T_2 \quad \text{(I-26)}$$

Here $T_1 = f_1\left(\frac{T_1'}{T_2'}\right)$ and $T_2^2 = \frac{T_1 T_2'}{2}$ (see Fig. I-5*d* and [I-4]).

The greater T_2 as compared to T_1, the greater the oscillations. Therefore, the constant T_1 determines the damping of the element and the constant T_2, its amplitude. When no damping occurs the element is a harmonic oscillation source.

Pure gain element, in other words an ideal element, allows the output parameter to increase with such a small time constant T, that the term $T\frac{dy}{dt}$ in (I-16) may be neglected. In this case the dynamics equation of the element has the form

$$y = kx \quad \text{(I-27)}$$

which coincides with the static characteristic equation.

Differentiating and integrating elements. Automatic control systems also use elements whose action depends on the derivative of the variable being controlled (differentiating elements) and on the integral value of the variable (integrating elements).

The equation of the differentiating element is as follows:

$$y = k_1 \frac{dx}{dt} \quad \text{(I-28)}$$

and that of the integrating element

$$y = k_2 \int \frac{dx}{dt} \quad \text{(I-29)}$$

The introduction of derivatives into the control equation facilitates the control process. An integral in the control equation allows the influence on the variation in the value of the controlled variable to be continued even when the mismatching quantity decreases to a very small value, hence, the value of the static error is reduced, i.e., the control becomes astatic. The effect of the differentiating elements on the control process can be obtained by the use of elastic feedback. If the control equation can be described by a differential equation of the first, second or third order, then the control (regulation) systems are called control systems of the first, second and third order respectively.

Performance analysis of distinct control systems begins with describing the control process by a system of differential equations. To choose the optimum parameters of the system, means investigating the process differential equations and finding suitable coefficients for the characteristic equation. However, the final adjustment of the automatic control system used to control a power system is carried out experimentally, as mathematical equations cannot always describe completely the operation characteristic of a power system. Therefore, when further discussing control devices for control of the power systems we do not require detailed mathematical analysis. The above definitions and characteristics were introduced in order to impart some idea of the processes occurring in certain elements used in control equipment.

I-4. Relays and Relaying Devices

Automatic devices pertaining to relays or relaying devices have four essential elements. These are *detecting*, *actuating*, *delaying*, and *controlling* elements.

The detecting element responds to external variables and abruptly changes the state of the actuating element when the external variables reach certain values (the position of the contacts, if used; change of resistance, inductance or electromotive force in the controlled circuits of contactless design; and actuation of the tripping mechanism in case of direct action relays).

The element which introduces a lag in the relay operation is called the delay element or the time delay element. If the actuating element effects changes in the pick-up settings of its detecting element and detecting elements of other devices, such an actuating element is called the control element.

The properties of a relaying device, i.e., the relaying operation, may be featured by many automatic devices employing electromechanical, electropneumatic, electromagnetic or electrohydraulic apparatus, vacuum tubes, semiconductors, magnetic elements and the like. These operating conditions are used also by various types of switches and circuit breakers, the actuators of which control the closure and opening of power networks.

More than that, the relaying mode of operation is also known for the fact that a small change in the external factor which a detecting element senses can cause a wide variation in the quantities under control of the actuating element, which are characteristic of other external phenomena. Hence, the external factor effect is multiplied many times. If this is so, the relay involved is considered to be an amplifier with a high gain factor or a trigger.

Like in the protective relaying devices, the relays employed in an automatic control system control mainly electrical circuits. The actuating element can act on the circuit with or without contacts. As to their function, the relay contacts are making, breaking, double-throw or impulse (variable) contacts.

Relays may be of a two-position type in which case the state of the actuating system (element) may be either operative or inoperative, and of a multiposition type when there may be more than two positions of the actuating element, depending upon the magnitude of the externally acting factor.

If the actuating element and all the working parts automatically return to their initial position when the external factor no longer acts the relay is called "self-resetting" and, if the working parts remain in contact, the relay is called a "seal-in" relay. When a relay does not reset instantaneously but only after some length of time it is termed a "time-delay" relay.

The pickup value (parameter) P_p is the minimum value of the external factor which causes response of the detecting element. An example is the closure of making contacts or the opening of breaking contacts.

The drop-out value P_d is the maximum magnitude of the external factor which causes response of the detecting element and makes the actuating element perform the reverse of the pickup operation.

The reset value P_r is the largest magnitude of the external factor which causes response of the detecting element and makes all the elements of the relay return to the initial state.

The pickup and reset parameters should not be confused with the relay must-operate parameters when picking up or dropping out, i.e., with those values of the external factor (minimum in picking up and maximum in dropping out) at which qualitative changes occur inside the relay. Those are requisite but not always sufficient to cause the pickup or dropout operation.

Of importance for performance analysis of various automatic devices is the reset — pickup ratio given by

$$k_r = \frac{P_r}{P_p} \tag{I-30}$$

Nowadays, there are many methods which permit the k_r value to be approximated to unity in various relaying devices. This adds to the sensitivity of the detecting elements.

The relays are distinguished as the relays that respond to current, voltage, impedance, power, etc.; the relays responding to the duration of a phenomenon (timing relays); the relays responding to the sequence of events (logic operation elements); the pulse frequency relays (counting devices), etc.

Besides, the relays are distinguished by the range of quantity values which the detecting element responds. These are "over" and "under" (maximum and minimum) relays, and quantity sign relays such as directional and polarized relays.

The reset-pickup ratio k_r is less than unity for overcurrent and overvoltage relays and more than unity for undercurrent and undervoltage relays. When constructing circuits for automatic control, however, all relays are presumed to be under storehouse conditions (i.e., deenergized) and function when the variable under measurement increases in excess of the operating setting. Under such conditions k_r is always less than unity and the minimum relays with making contacts are considered as maximum relays with breaking contacts.

Relays can be electrical, mechanical, hydromechanical, thermal, optical, etc.

Depending upon the condition of the variables controlled by the relay, distinctions are made between protective, supervisory, overload, correspondence, synchronizing, etc. relays.

As to their position in the equipment and the functions performed, relays are classified as primary when the detecting element is connected directly to the circuit whose variations make the relay function; secondary relays when the detecting element is connected into the circuit under control via an inductive or capacitive coupling device; slave relays which serve as an intermediate element in the equipment circuit; timing relays which provide the required time lag in the device; indicating relays which show the condition of the whole or individual elements of the actuating device, etc.

With respect to the phenomena used in the performance of relays they are classified as electromagnetic, polarized, semiconductor, electronic induction, photoelectric, ferromagnetic, etc.

Relays are also classified with regard to the pickup and reset time (t_p and t_r), i.e., the time elapsed from the instant the acting factor reaches the point at which the detecting element comes into action (the pickup or reset magnitude) to the instant the actuating element operates or resets. Distinctions are made between very high-speed (microsecond) relays the time of which may be conventionally accepted to be not over one period (0.02 second), high-speed relays with the time ranging from 0.02 to 0.04 second, instantaneous acting relays whose time is from 0.04 to 0.08 second, and slow-acting relays whose performance is delayed by a special member providing a delay time adjustment or whose response time depends on the magnitude of the parameter to which the detecting element responds (inverse-time relays).

I-5. Elements of Logic Operations

YES, *NOT*, *AND* and *OR* operations. The *YES* function is performed by the operation of an actuating relay (Fig. I-6*a* and *b*). Nonoperation of the relay

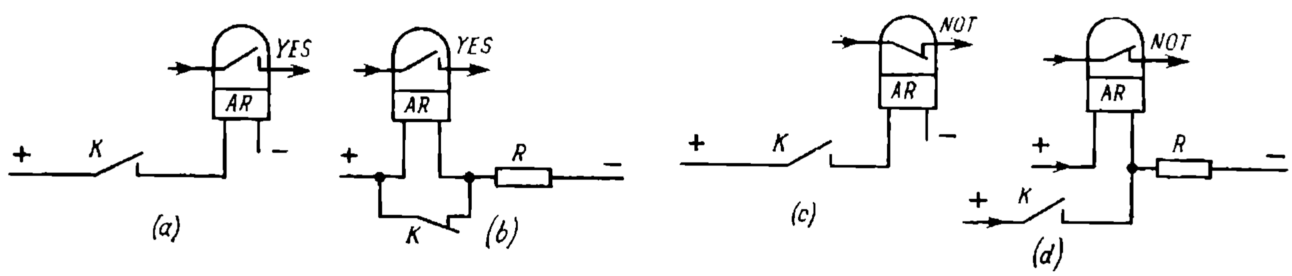


Fig. I-6. Performing YES (*a*, *b*) and NOT (*c*, *d*) logic operations by contact-type relays

(*a*) when contact *K* closes; (*b*) when contact *K* opens; (*c*) when contact *K* makes the circuit of relay *R*; (*d*) when contact *K* bypasses the circuit of relay *AR*

is characteristic of the *NOT* function. The relay may be of any type which ensures a two-position, stable and positive action. The *NOT* instruction can be realized by the schemes shown in Fig. I-6*c* and *d*.

The *AND* operation is realized by closing the making contacts of the actuating relays in series (Fig. I-7). The output signal is formed only when both relays *1AR* (*1П*) and *2AR* (*2П*) are closed.

The OR operation is obtained by parallel connection of the actuating elements (Fig. I-8). The output signal will be formed when either of the relays *1*, *2*, or *3*, etc. is operated.

Comparison operation. The effects of electrical variables A and B can be compared mechanically or electrically. The mechanical method is illustrated in Fig. I-9. When comparing the effective magnitudes of alternating current the operating time of the detection element must be not less than one period, as the

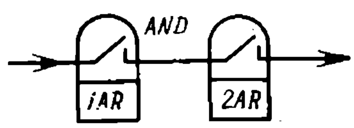


Fig. I-7. Performing AND logic operation by contact-type relays

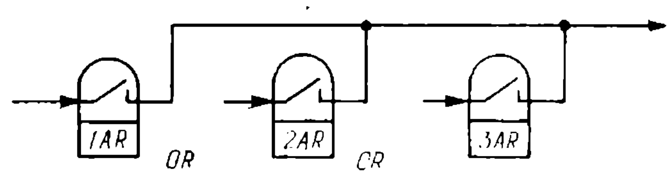


Fig. I-8. Performing OR logic operation by contact-type relays

effective value of an alternating current is assessed over one period. When comparing the magnitudes of direct current or rectified alternating current the minimum time is limited only by the physical properties of the relay.

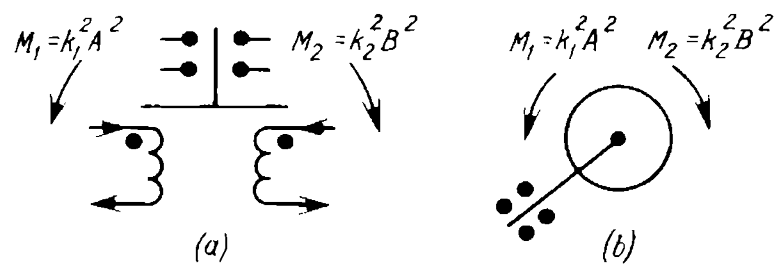


Fig. I-9. Mechanical comparison of electrical magnitudes
(*a*) with electromagnetic system; (*b*) with induction system

The ratiometer principle can be used to compare d.c. magnitudes (Fig. I-10). The deflection angle α of the moving coil instrument depends on the quotient of the currents flowing in the loop coils

$$\alpha \equiv \frac{A}{B}$$

Comparison may be accomplished by a two-position relay, in particular, a polarized relay in which the armature movement depends on the direction of current flowing in the coils.

To compare quantities $|\dot{A}|$ and $|\dot{B}|$ a null indicator may be used. When the quantities $|\dot{A}|$ and $|\dot{B}|$ are equal and voltage balance is obtained, no current flows through the indicator. The current flows in one direction, if $|\dot{A}| > |\dot{B}|$, and oppositely if $|\dot{A}| < |\dot{B}|$. The circuit can be designed to respond to a current or voltage difference (Fig. I-11*a*, *b*).

Induction devices may serve as comparison elements as their torque is dependent on the magnitude and direction of the magnetic fluxes produced by the quantities being compared. The same principle underlies the operation of the so-called differential synchros which have two operating opposing coils. Another comparison method is the electromagnetic one. The use of different

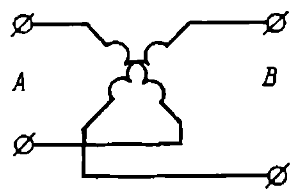


Fig. I-10. The use of ratiometer moving system for performing COMPARISON logic operation

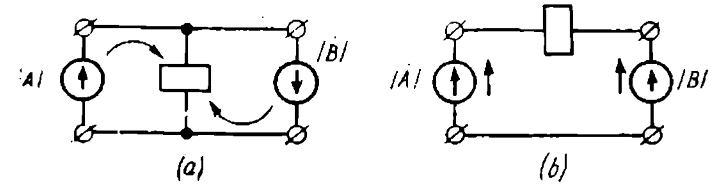


Fig. I-11. Null indicator circuits
(*a*) current balance; (*b*) voltage balance

windings on a common magnetic circuit core of a relay or of a magnetic amplifier is an example. In this case the effects of magnetic fluxes Φ1 and Φ2 produced by the current flowing in the windings are compared.

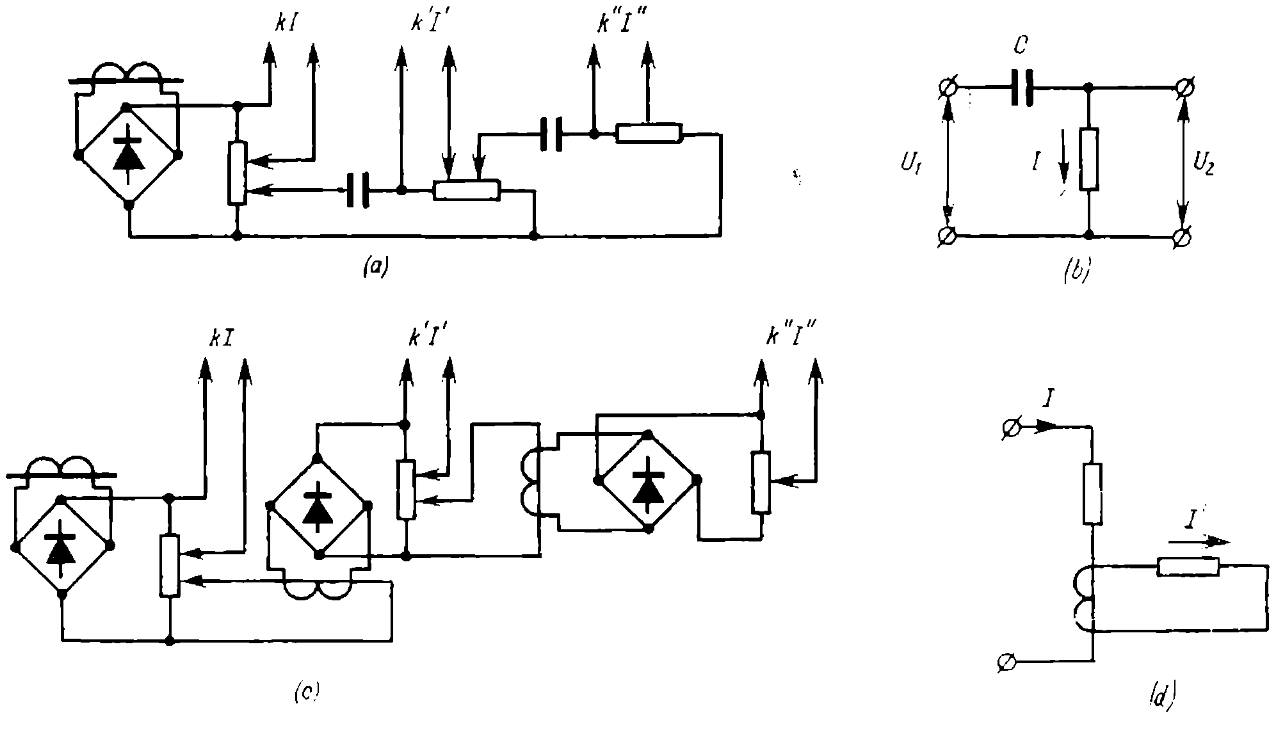


Fig. I-12. Circuits of differentiating devices

All the above-mentioned principles are employed in protective relaying and automatic control systems. Their application often depends on the level of production technology, patent policy and their compatibility with other pieces of equipment.

Differentiating elements. The operation of a differentiating device is shown in Fig. I-12.

Alternating current, for example, generator stator current, is rectified and fed to a differentiating network composed of a resistor and a capacitor (Fig. I-12*a* and *b*) or to the primary winding of a coupling transformer (Fig. I-12*c* and *d*). The voltage across the resistor of the differentiating network is proportional to the current in the resistor. The current is proportional to the capacitor charge.

$$I = \frac{U_2}{R} = C \frac{d(U_1 - U_2)}{dt} \tag{I-31}$$

i.e.

$$U_2 + RC \frac{dU_2}{dt} = RC \frac{dU_1}{dt} \tag{I-32}$$

If $RC \frac{dU_2}{dt} \ll U_2$, then

$$U_2 \approx RC \frac{dU_1}{dt} \tag{I-33}$$

The output signal taken from a differentiator of the type shown in Fig. I-12*b* (a passive differentiator) is small and usually requires amplification. In the

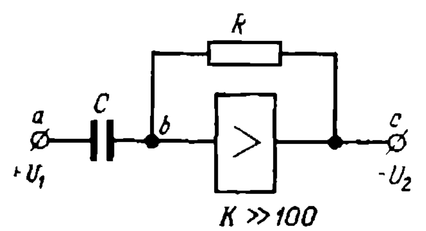


Fig. I-13. Variant of a differentiating element

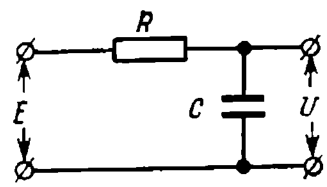


Fig. I-14. Integrating element circuit

circuit shown in Fig. I-12*c* and *d* the current in the secondary winding of the coupling transformer

$$i = \gamma \frac{d\Phi}{dt} = k' \frac{dI}{dt} \tag{I-34}$$

A signal proportional to the second derivative can be obtained by a second differentiation of the current proportional to the first derivative of the controlled variable. If the parameter being regulated is alternating current proportional to the current in the protected or automated circuit, then a signal proportional to this variable should be first obtained as direct current and passed through an automatic differentiator.

The differentiating element may be constructed as shown in Fig. I-13 with an amplifier and direct feedback. A large amplifier gain factor is essential. As compared to the feedback circuit impedance the amplifier input impedance is very high, for which reason the current branched to the amplifier input is fairly small. For the above-mentioned reason the potential at the node *b* attains a zero value in comparison to the potential at the nodes *a* ($+U_1$) and *c* ($-U_2$). If it is assumed that the potential of the node *b* approximates zero, then the

transient process may be written as follows

$$i = C\frac{dU_1}{dt} = -\frac{U_2}{R} \tag{I-35}$$

hence

$$U_2 = -RC\frac{dU_1}{dt} \tag{I-36}$$

Integrating elements. The operating principle of an integrating device can be understood from the scheme in Fig. I-14 (a passive integrator). The expressions for the circuit are

$$iR + \frac{1}{C}\int i\,dt = E \tag{I-37}$$

and

$$\frac{1}{C}\int i\,dt = U \tag{I-38}$$

Since

$$\int i\,dt = CU \tag{I-39}$$

and

$$i = C\frac{dU}{dt} \tag{I-40}$$

then

$$RC\frac{dU}{dt} + U = E \tag{I-41}$$

or

$$\frac{dU}{dt} + \frac{U}{RC} = \frac{E}{RC} \tag{I-42}$$

If the ratio U/RC is neglected as compared to the magnitude of E/RC, then

$$\frac{dU}{dt} \approx \frac{E}{RC} \tag{I-43}$$

hence

$$U = \frac{1}{RC}\int E\,dt \tag{I-44}$$

The integrating element may employ the scheme shown in Fig. I-15. Taking into account that the potential of the node b is negligibly small as compared to the $(+U_1)$ and $(-U_2)$ values

$$i = \frac{U_1}{R} = -C\frac{dU_2}{dt} \tag{I-45}$$

whence

$$U_2 = -\frac{1}{RC}\int U_1\,dt \tag{I-46}$$

A d.c. or a.c. motor may also be used by the integrating element. The operating principle of such an integrating element can be seen from Fig. I-16. The input signal caused by the mismatch between the actual value of the controlled variable and the specified magnitude drives the motor. Depending upon the mismatch duration, the motor moves the slider of a potentiometer whose output signal is given by the position of the potentiometer slider, i.e. by the total

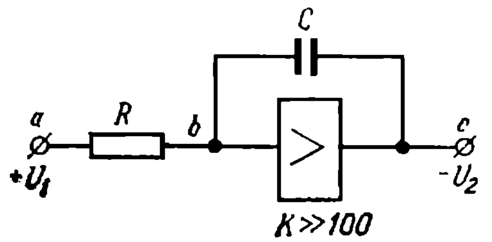


Fig. I-15. Integrating element

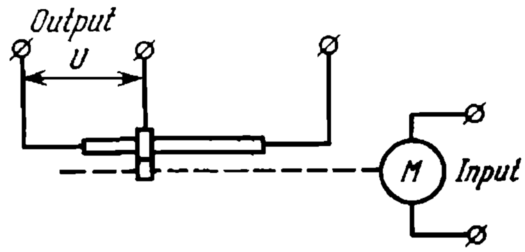


Fig. I-16. The use of motor in integrating element

(integral) error between the actual and specified magnitudes of the controlled variable. The control system employing an integrating element of this type must have feedback between the controller output and the input signal.

Multiplying elements. Different devices using vacuum tubes, semiconductors, magnetic elements, etc. to multiply a variable by a constant factor (amplifiers having a constant gain factor) are available.

Depending on the gain factor the output voltage (Fig. I-17*a*)

$$U_2 = k_g U_1 \qquad \text{(I-47)}$$

where k_g is the gain factor.

To keep the variables under control and the gain factor constant, a network with a direct feedback effected through resistor R_2 may be applied. One pole of the amplifier on the input and output sides is earthed and the voltage of the other pole is indicated with regard to the earth potential. The amplifier is so connected that the input and output voltages are of opposite polarity, plus, say, at the input and minus at the output. To simplify the graphical representation, the earthing contact of the other pole is not shown. For adequate operation of the equipment, an amplifier having a high gain factor (k_g ranging from 100 to 1000 and more) should be used.

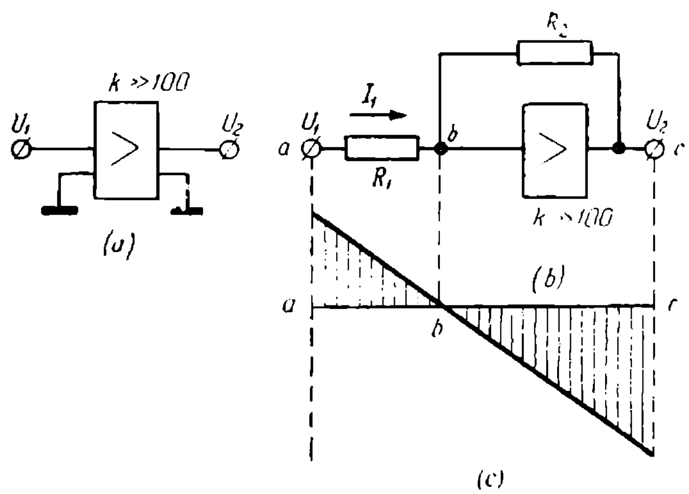


Fig. I-17. Multiplying element

With an adequately high gain factor (k_g being far greater than 100) the node b has a negligibly small potential (relative to earth) as compared to the voltages of nodes a and c. Therefore, the potential diagram has the form shown

in Fig. I-17*c* with a minute zero drift. Since the current

$$I_1=\frac{U_1-u}{R_1}\approx\frac{u-U_2}{R_2} \tag{I-48}$$

then, with adequate accuracy we assume

$$\frac{U_1}{R_1}=-\frac{U_2}{R_2} \tag{I-49}$$

and

$$U_2=-\frac{R_2}{R_1}U_1 \tag{I-50}$$

Under these conditions the output voltage U_2 is practically independent of the gain factor k_g of the amplifier. Thus, the device automatically multiplies

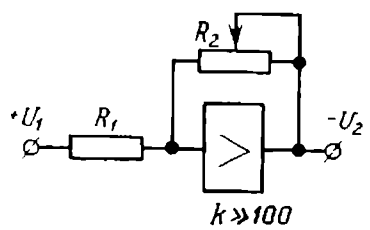


Fig. I-18. Multiplying element circuit

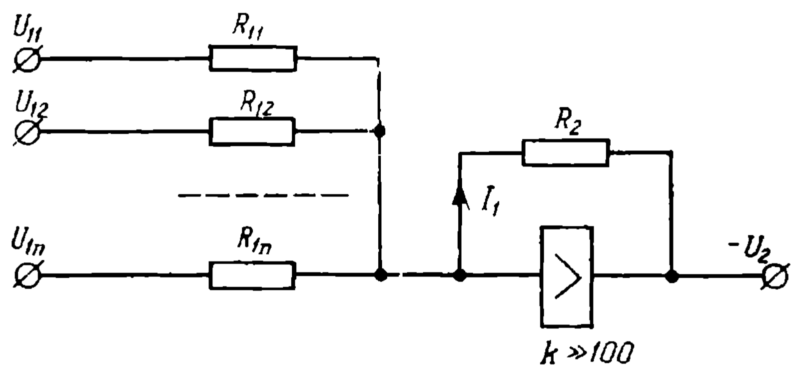


Fig. I-19. Summing network

the multiplicand U_1 by the multiplier R_2/R_1 whose value is controlled by adjusting the R_2 and R_1 magnitudes. The multiplying mesh has the form shown in Fig. I-18. The device may be used to keep the terminal load voltage constant, R_l being the load resistance, if $R_1 = R_2$, then $U_2 = -U_1$, regardless of the load magnitude.

Summing network. The effects of several quantities can be summed mechanically, electrically or electromagnetically. Treated below is one of the possible ways of performing summation operations electrically with a simple mesh (Fig. I-17*b*) employing the scheme shown in Fig. I-19. In compliance with formulae (I-48 and I-49).

We may write

$$I_I=\frac{U_{11}}{R_{11}}+\frac{U_{12}}{R_{12}}+\ldots+\frac{U_{1n}}{R_{1n}}=-\frac{U_2}{R_2} \tag{I-51}$$

hence

$$U_2=-R_2\left(\frac{U_{11}}{R_{11}}+\frac{U_{12}}{R_{12}}+\ldots+\frac{U_{1n}}{R_{1n}}\right) \tag{I-52}$$

Inverters. The network shown in Fig. I-17*b* inverts the sign of the input quantity, i.e., multiplies by (—1).

When $R_1 = R_2$

$$U_2=-U_1$$

I-6. Connection Diagrams

The interaction of individual elements in automatic electric power devices is realized first by representing it in an electrical circuit diagram and then by analyzing its function. Proper construction of a diagram, its clarity of representation, and easiness of interpretation by the person who reads it are not secondary design tasks. Operation of any device in the automatic control system without a circuit diagram is impossible.

In compliance with the terminology of the unified system of design documentation [I-1] the electrical circuit diagrams are divided into block diagrams, functional diagrams, schematic diagrams, wiring diagrams, connection diagrams, installation diagrams and layout diagrams.

The block diagram, defines the essential functional components of the device, their applications and interrelationships. It shows the overall operation sequence of its separate units employed without detailing the internal design of the units. The units are designated by capital letters which indicate the type or application. Examples are CU, Comparison unit, SU Supply Unit; YES, NOT, OR, AND logic operation units; TU, Time Delay Unit; MU Measurement Unit; DFBU Direct Feedback Unit; AU Amplifier Unit; etc.

The functional diagram explains certain processes which take place in individual circuits of the device (equipment) or in the device as a whole.

Depicted in the functional diagram are the functional components of the device (elements, units and functional groups) which are involved in the process illustrated by the diagram and the relationships between these components. Actual couplings between the elements and units may be shown in these diagrams.

The schematic diagram identifies all the components, shows their relationships and, as a rule, gives a detailed idea of the operating principles of the equipment. The schematic diagrams may be either combined or developed.

Conventional symbols are used to show the detecting and actuating components on the combined schematic diagrams of the electrical control device. These components have their actual location as specified on the diagram. In three-phase equipment, the devices are shown connected to instrument transformers, while the latter are drawn wired to the phase conductors of the primary circuit as in actual service. A schematic diagram so constructed is combined with the *connection diagram*, i.e., with a diagram which shows the external connections of the equipment.

The combined schematic diagrams must illustrate completely the interrelationships of the elements in the device as well as that among the devices. All apparatus used must be shown on such diagrams. Major units including a series of devices and relays, are depicted either as a single apparatus or as several electrically connected devices enclosed by a dotted line indicating a complex design. If a major unit is shown as an apparatus without illustrating its internal wiring, a clarifying drawing must be given.

The developed schematic diagrams which are sometimes called element diagrams show electrical circuits from beginning to end, for example, from the positive terminal post of a storage battery to its negative terminal post or from

one terminal of an instrument transformer to its other terminal. The electrical circuits are shown by horizontal and/or vertical lines. As compared to the combined schematic diagrams the developed schematics make it easier to check the correctness of electrical connections and absence of by-pass faults. Separate developed schematic diagrams are constructed for operative circuits, signalling circuits and for the secondary current and voltage circuits of transformers.

The developed schematic diagrams of electrical control circuits can be combined with developed diagrams of operative circuits, instrument and signalling circuits. Such diagrams are developed diagrams with regard to the operating current. Developed schematic diagrams are usually supplemented with textual references explaining and making it easier to understand the operation of the scheme circuits.

Wiring diagrams are working drawings used by practical electricians when installing secondary circuits. Shown on the diagram are electrical connections made between components by means of wires, harnesses and cables, as well as terminals, connectors and other commutating devices. The nature and form of a wiring diagram should be specific for the place of installation and comply with manufacturer's specifications when the factory produced panels are used for control, protection and automatic operation purposes.

To assure correct laying of control cables and to make equipment servicing feasible, all the devices and circuits on the diagram must be identified in the same manner. Wires are marked at the sleeve ends near the panel or device terminal to which the wire is connected. With many wires bundled into a harness, use is made of wiring tables denoting the terminal to which each wire (its No.) must be connected.

Widely used are wiring diagrams. These are completely developed schematic diagrams which bear the identification (marking) of each wire and terminal of the equipment.

In addition to the above-described diagrams, the State Standard (GOST) specifies the construction of *installation diagrams* which show the major components of a set and their interconnections and of *layout diagrams* dealing with the physical position of major components and also with the arrangement, if necessary, of the wires, harnesses and cables. An example is the arrangement of equipment details on panels or in complex relays.

I-7. Conclusions

1. In the USSR automatic power control systems intended to increase the dependability and efficiency of power systems and lighten the labour of servicing personnel have been brought into practice over many years. Nowadays these devices are well engineered and form an automatic power control system assemblage (automatics). Their use during many years has proved the high efficiency of such control systems and demonstrated their importance in the national economy. The costs of automatic power control systems are incommensurably small as compared to the economy resulting from the decrease in the fault rate and increase in the transient links capacity.

2. Automatic power control systems make electrical operations of power systems automatic, they are intimately tied with the operation of protective relaying devices, radically improve maintenance and also generation and distribution of electrical power and become more and more performance elements of power systems.

3. Automatic power control systems are built up of various types of transducers, controllers and relays operating in conjunction with intermediate automatic elements such as amplifiers, rectifiers, stabilizers, time-delay devices, differentiating and integrating elements, memory systems, etc. The performance of automatic power control systems obeys the general laws inherent in various control devices or in devices performing relaying operations.

4. The practical use of an automatic power control system should be effective, i.e., must be advantageous and economically sound as well as quickly repaying its cost.

5. At equal costs of using remote or automatic control of some process, preference should be given to the use of automatic control systems as this renders unnecessary personnel attending to the control process, thus adding to operation reliability and rapidity of control. With automatic control, the attending personnel's allotment in control and service only means compiling the performance program of the device and maintaining it in good condition.

6. One of the essential requirements for automatic power control systems is their reliability. The reliability of automatic power control systems and protective relaying devices obeys the general regularities of the reliability theory for widely used devices with due thought given to their specific working features. The probability of trouble-free operation may serve as the reliability criterion. The possibility of employing this criterion for continuous automatic controls such as regulators is clear-cut. With discrete operating automatic controls, distinctions are made between the modes of operation such as "waiting time" and "alarm". It is important in the practical use of devices included in the family of automatic control systems that the elements employed are dependable, the design is accomplished well, the assembly operations are performed to high standards and the system works well at all times.

7. The graphical representation of the diagrams of the automatic controls should clearly indicate the interrelationships between the units and be easily interpreted to facilitate installation and operation.

I-8. Review Questions

1. What automatic devices are included in the assemblage conventionally called "automatic power control systems"?
2. What is the relationship between operation of individual elements of the automatic power control system and protective relaying?
3. What are the requirements for diagrams depicting devices of automatic power control systems and protective relaying?
4. What are the essentials of relaying devices? Name the distinctive features encountered in the operation of transducers, relays and controllers (regulators).
5. What are the pickup and reset values of a relay? Define the reset-pickup ratio.

6. What is the purpose of an amplifier in a control system? Describe the performance of a relay used as an amplifier.

7. What is the purpose of feedback in automatic control devices? Describe positive and negative feedbacks. Describe the direct (continuous) and elastic (sample-data) feedbacks.

8. What are the specific features of the control by the absolute value of the departure of a controlled variable from the specified value and by the absolute value deviation with the control by the rate of deviation added?

9. What are control elements? Describe integrating and differentiating elements.

10. What are the logic operations used in the operation of automatic devices?

11. Explain the terms "astatic and static characteristics" of control processes. Define the term "static coefficient".

12. What are the static and dynamic characteristics of the elements of a control system? What is static error? Describe the methods for its decreasing.

13. What are the features of aperiodic and oscillating control processes?

14. Explain the difference between the remote control and automatic control of certain processes carried out in power systems. Name the advantages of the automatic control.

15. What is the overall effect on national economy of the use of automatic power control systems? How can this effect be determined?

16. Explain reliability of automatic power control systems as one of the principle requirements for their devices. What are the methods used for quantitative estimation of the reliability?

17. Describe the electrical connection diagrams of automatic power control systems. Explain the types and purposes of electrical connection diagrams.

Chapter One

AUTOMATIC CONTROL OF SYNCHRONOUS GENERATOR EXCITATION

1-1. Purpose of Automatic Excitation Control (AEC) Devices

The excitation control process is automated with a view to achieving a multifold goal, namely, to increase the reliability in the parallel operation of individual generators and the power system as a whole, to control within certain limits the voltage across system units, and to increase the speed at which the operating voltage is restored to its rated value after clearing short-circuits.

The automatic excitation forcing device is a most simple one which has a discrete effect on the excitation system of a synchronous machine for increasing the field current to a critical value permitted by the rotor overload rating. This device is employed either separately or together with voltage regulating devices. The excitation forcing device functions, when the voltage under control drops to 85% of the rating [1-1]. It is generally made up of ordinary relays and a contactor. In complicated controllers the excitation forcing device is only one of the controller elements.

Depending on the *variable* to which they respond and on the *type* of response, the AEC devices employed in the Soviet power system may be either *proportional action* or *overaction controllers*. The former group includes automatic excitation controllers which respond to the polarity and value of variations in the current and voltage. The latter group comprises automatic excitation controllers which respond both to the polarity and amount of variations in the voltage and current and also to the rate of changes in these and other variables involved.

The proportional type excitation controllers used in the power systems of the USSR are available mainly in the form of compounding devices with an electromagnetic voltage corrector designed by the Electrical Engineering (Electrodynamics) Institute of the Ukrainian Academy of Sciences. The overaction controllers were developed by the Lenin All-Union Electrical Engineering Institute.

Compounding devices with an electromagnetic voltage corrector automatically change the excitation in proportion to the current flow in the stator circuit and the voltage across the generator terminals or at a specified point in the circuit. Their functioning is relatively slow and accompanied by a static error in the voltage, which is corrected to a certain extent by the operation of the excitation forcing device.

In the presence of a quick-operating excitation system the overaction controllers assure quick control and maintain the voltage across the stator winding

terminals or across the output terminals of a step-up transformer (when the generator operates jointly with a transformer) practically constant. These controllers function without a perceptible static error. The excitation forcing device employed in these controllers has the function of a stand-by element and speeds up the control process.

As mentioned previously, the wide use of excitation forcing and control devices in generators and synchronous capacitors materially improve the reliability of power systems. The use of AEC devices is of special importance for improving parallel operation stability.

Let us study this problem in detail.

To this end, let a synchronous generator operate in parallel with a high-power system through a power transformer and a transmission line (Fig. 1-1).

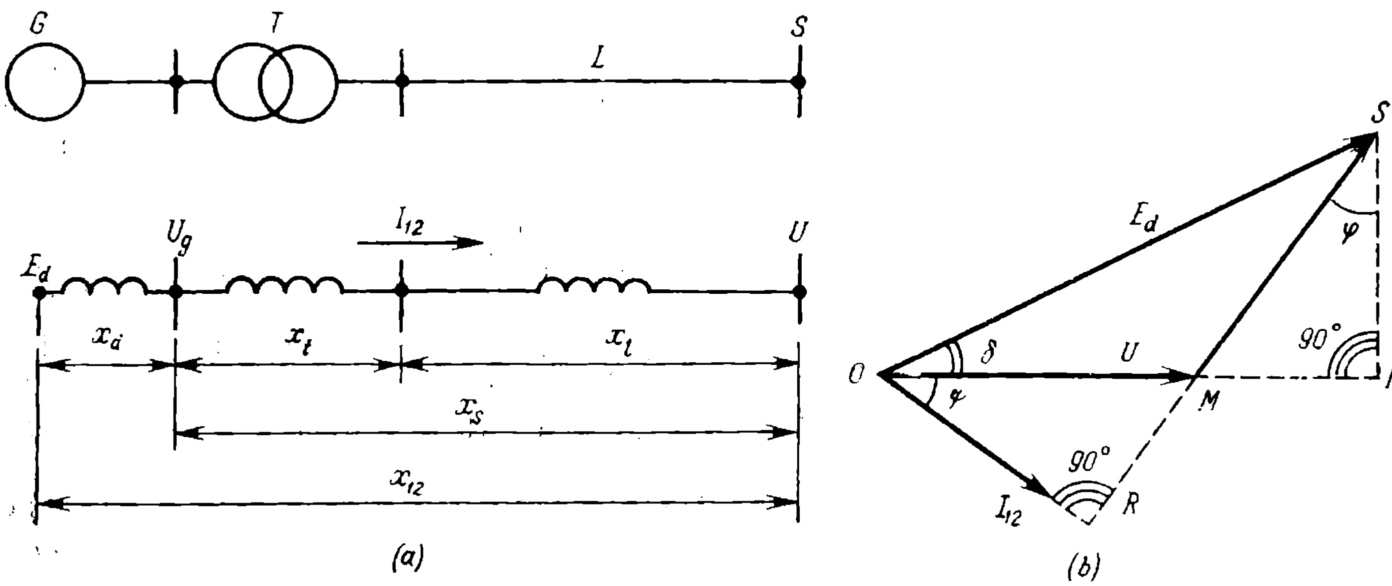


Fig. 1-1. Operation of synchronous generator in power system
(a) equivalent circuit; (b) vector diagram

Denote the generator emf by E_d, the busbar voltage of substation S used in a high (infinite) power system by U and the impedance between the emf application point and the busbars of substation S by x_{12}.

The current I_{12} flowing against impedance x_{12} and the active power output P fed by the generator into the power system are, respectively, as follows:

$$|\dot{I}_{12}| = \left|\frac{\dot{E}_d - \dot{U}}{jx_{12}}\right| = \left|\frac{\overline{SM}}{jx_{12}}\right| \tag{1-1}$$

and

$$P = UI_{12}\cos\varphi \tag{1-2}$$

It is seen from Fig. 1-1*b* that in triangle MSN angle $MSN = \varphi$ and side $SN = SM\cos\varphi$.

Since from (1-1)

$$SM = I_{12}x_{12}$$

and from triangle ONS

$$SN = E_d \sin \delta$$

then

$$E_d \sin \delta = I_{12} x_{12} \cos \varphi$$

Taking into account (1-12), we obtain

$$P = \frac{UE_d}{x_{12}} \sin \delta \tag{1-3}$$

The maximum magnitude of active power (P_m) which can be transmitted corresponds to the value of $\sin \delta = 1$, i.e.

$$P_m = \frac{UE_d}{x_{12}} \tag{1-4}$$

and

$$P = P_m \sin \delta \tag{1-5}$$

Expression (1-3) does not take into account the presence of a resistance component (r_{12}) of the impedance. Such an assumption may be made for a qualitative analysis of parallel operation stability.

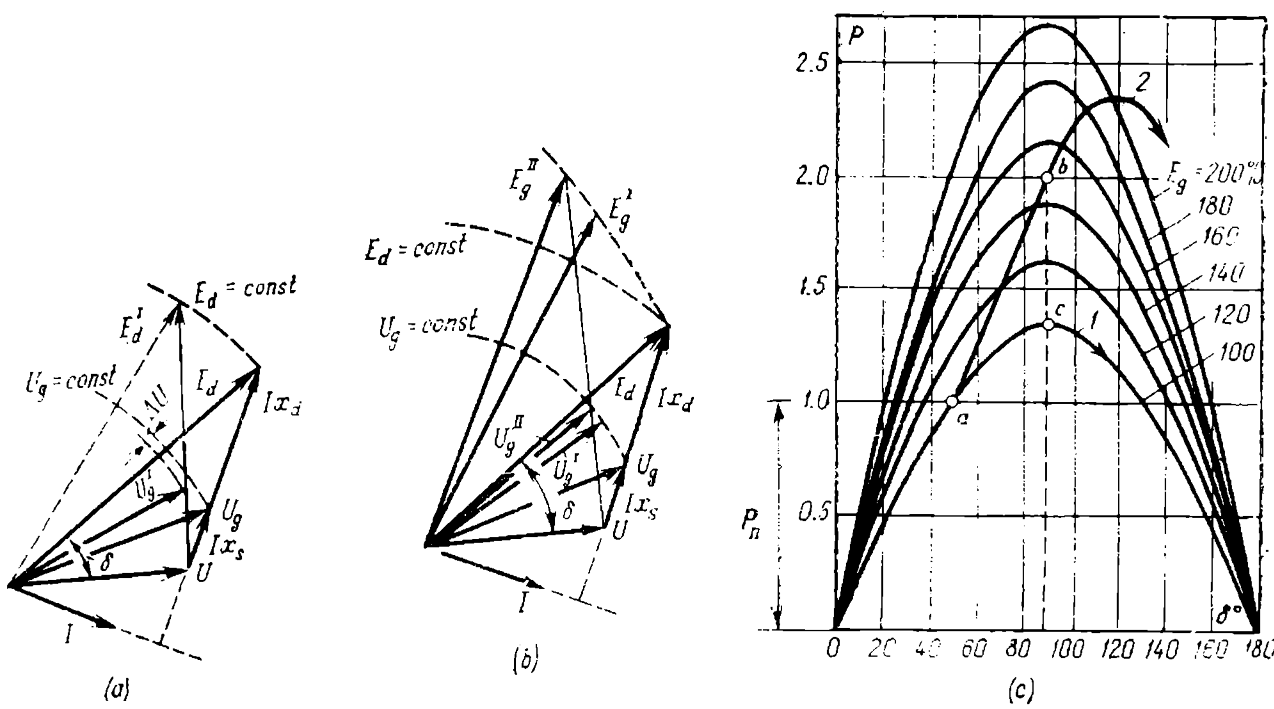


Fig. 1-2. Effect of AEC operation on increase in static stability

(a) changes in terminal voltage of generator when E_d is constant and angle δ increases; (b) changes in emf of generator when generator terminal voltage is maintained constant and angle δ increases; (c) characteristic of changes in power when U_g is constant

How the operation of AEC devices increases the steady-state (static) stability can be seen from Fig. 1-2. When no automatic excitation controller is used the generator emf is determined by the invariable value of field current and

remains constant under fault conditions (E_d = const). The voltage across the generator terminals equals vector U_g which divides the section UE_d into parts proportional to the values of the generator synchronous inductive reactance (x_d) and the impedance of the remaining portion of the system (x_s).

As the load angle δ increases, i.e., with an increase in the power being transmitted, the emf vector on the diagram takes the position $\dot{E}_d^I$ and the vector of the voltage across the generator terminals is determined by the vector $\dot{U}_g^I$, then

$$\frac{|\dot{E}_d-\dot{U}_g|}{|\dot{U}_g-\dot{U}|}=\frac{|\dot{E}_d^I-\dot{U}_g^I|}{|\dot{U}_g^I-\dot{U}|} \tag{1-6}$$

As seen from Fig. 1-2*a*, $|\dot{U}_g^I|$ is less in value than $|\dot{U}_g|$, i.e.

$$|\dot{U}_g|-|\dot{U}_g^I|=\Delta U \tag{1-7}$$

If the detecting element (primary detector) of the AEC device responds to the value of ΔU and tends to maintain $\Delta U = 0$ by changing the field current of the generator, it will be seen from Fig. 1-2*b*, that the generator emf exceeds the E_d value.

When maintaining U_g = constant, the ordinates of the transmitted power characteristics exceed the ordinates of the curve plotted on the basis of (1-3) for the condition when E_d is constant, operation of the generator becomes feasible within the artificial stability region, i.e., when $\delta > 90°$ (Fig. 1-2*c*).

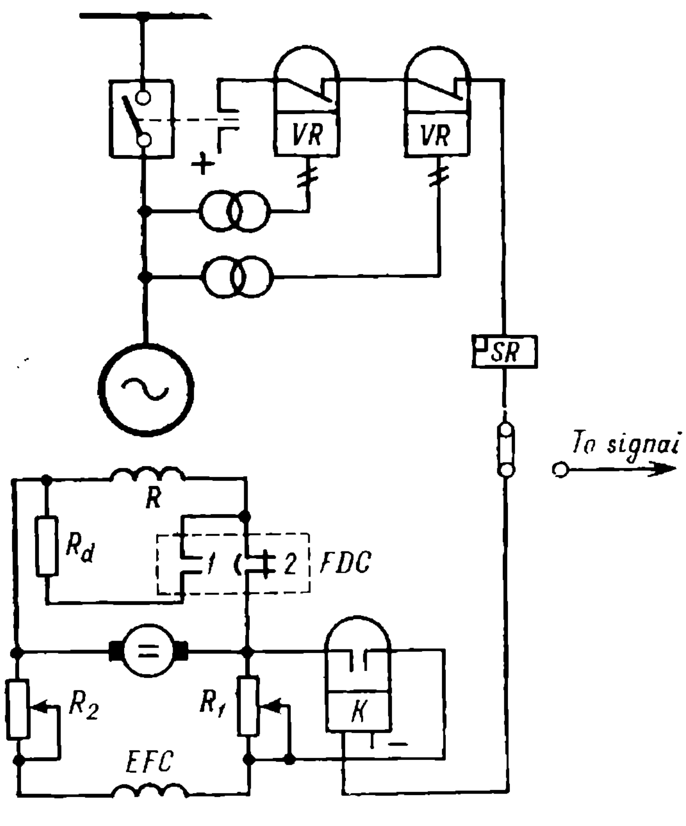


Fig. 1-3. Operating principle of a device for automatic excitation forcing

1-2. Automatic Excitation Forcing of a Generator

The operating principle of the quick-acting generator excitation forcing circuit is clear from the diagram shown in Fig. 1-3 which illustrates an electric machine excitation system furnished with an automatic field discharging control using discharge resistor R_d to absorb the power accumulated in the rotor winding. When voltage across the terminals of the stator winding (or at the specified point of the circuit) drops to the reset setting of voltage relay *VR*, the latter closes the contacts and shorts by means of intermediate contactor *K* resistance R_1 placed into the field coil circuit of the exciter.

The excitation current rises causing an increase in the generator emf. When forcing, damage to the field coil of the exciter is prevented by resistor R_2 which limits the current flow in this coil. In self-cooled exciters the forcing current is raised to a two-fold ceiling value with regard to the rating. Specially designed exciters employed a four-fold increase in the excitation current to ensure extra stability.

With forced-ventilated machines, forcing is permitted only for short periods (Table 1-1)[1-1].

Table 1-1

Permitted Excitation Forcing Duration for Forced-Ventilated Turbogenerators [1-6]

Turbogenerator type	Forcing factor				
	2	1.7	1.5	1.2	1.06
TVF (ТВФ)	30	60	—	240	3,600
TVV (ТВВ) and TTV (ТТВ)	20	—	60	240	3,600

With self-cooled machines, attending personnel must eliminate the cause of operation of the excitation forcing devices not later than one minute after the device has functioned. Protection of the rotor against overloads and limitation of rotor overload duration by deexcitation are specified in the service circular[1-2].

Shown in Fig. 1-3 is a circuit which provides for instantaneous reset of the forcing device after the voltage across the terminals of the *VR* relay has restored its value at which the relay contacts open. Circuits of this type are widely used. In order to maintain stability in after-fault operation, it is good practice to continue the excitation forcing action for a specified period after the fault cause has disappeared. In this case, the stability disturbances encountered in the second hunting cycle can be prevented in a number of instances due to the increased emf value used in the after-fault conditions.

The circuit used for the purpose is shown in Fig. 1-4. The reset delay of the excitation forcing device is obtained by a *DR* drop-out delay relay (relay *3*). To some extent the reset time of this relay depends on the short-circuit clearing time which determines the closed state period of the contacts of relays *1* and *2*, this facilitates the voltage recovery after the fault. The longer the short-circuit period, the greater is the forcing delay. Protection against an inadmissible forcing operation duration by relay *11* and contactor *5* (Fig. 1-4) is accomplished by voltage relay *6* and time relay *7*. Back-up protection is effected by relay *8* which disconnects the generator and kills its field voltage through the output relay when the protection functioning time is too long.

The circuit of the excitation forcing device is under the control of the interlock contact of the generator switch, which is closed when the switch is in the ON position.

The operation of the automatic excitation forcing device in conjunction with the action of the generator excitation system determines the regulation characteristic shown in Fig. 1-5. The pick-up voltage U_p at which the voltage

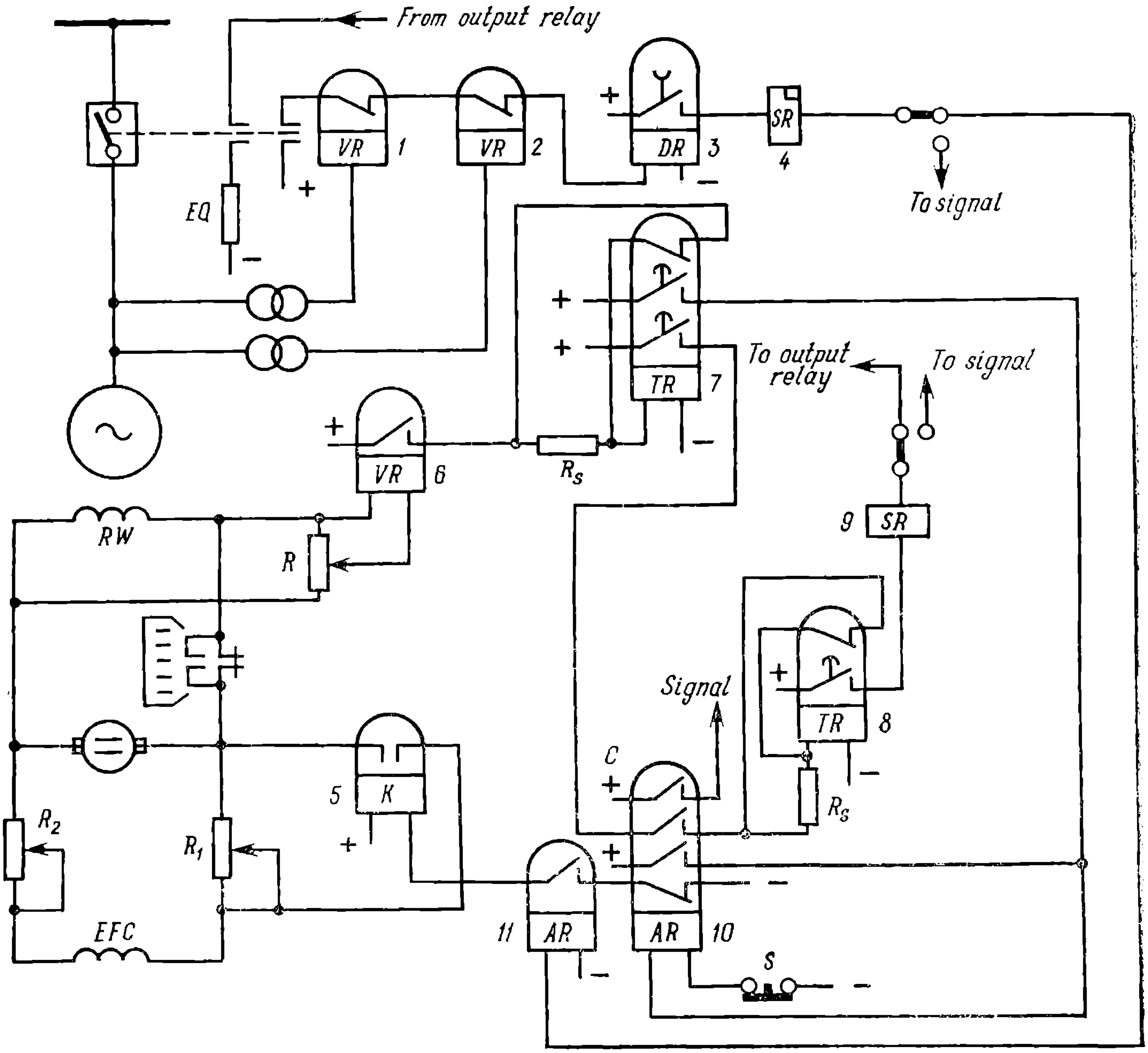


Fig. 1-4. Actuation of excitation forcing device with reset delay and limited forcing operation time

relays open the making contacts is selected as dictated by the adjustment conditions of the excitation forcing device so that it is not affected by the operating voltage U_l across the generator terminals, the margin (factor of safety) k_s being equal to 1.05. When the reset-pickup ratio (k_r) of the voltage relay equals 0.9, the contacts will close at the voltage across the relay (U_{relay}) equal to the reset

voltage U_r

$$U_{relay} = U_r = \frac{k_r}{k_s} U_l = \frac{0.9}{1.05} U_l = 0.85 U_l \qquad (1\text{-}8)$$

The higher the k_r of the voltage relay, the more effective is the performance of the excitation forcing device.

The circuits of the excitation forcing devices shown in Figs. 1-3 and 1-4 ensure the forcing operation in case of three-phase short-circuits and when faults

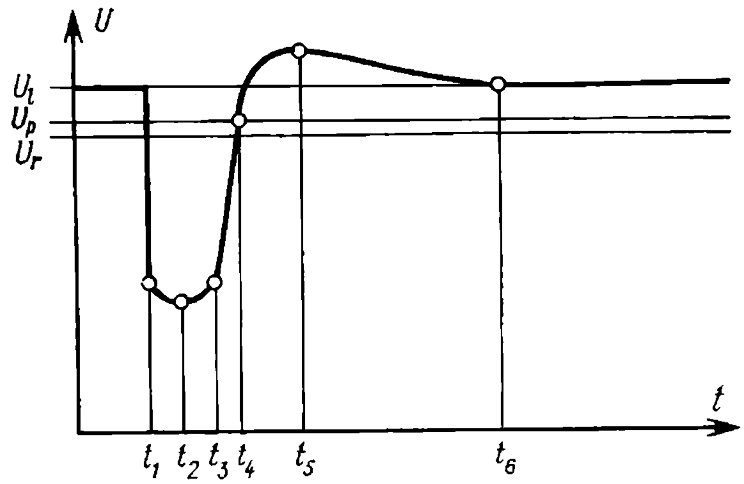


Fig. 1-5. Changes in voltage when a short circuit occurs and after it is cleared

t_1 — the instant a short circuit occurs; t_2 — the instant the excitation forcing device functions; t_3 — the instant the short circuit is cleared; t_4 — the instant the circuit voltage is reestablished to the value at which relays *1VR* and *2VR* (Fig. 1-4) open contacts; (t_5 to t_4) — time for relay *DR* to reset; t_6 — time for voltage to restore to the nominal value

occur between two phases to which the voltage relays are connected. When faults occur between the other two phases and in the case of an earth fault in the step-up transformer circuit on its HT side (in the circuit with a heavy earth fault current), the forcing system response becomes coarser and greatly depends on the distance to the point of short-circuit. In such cases, a fairly high voltage remains across the terminals of the generator stator due to the voltage drop and because of changes in the phase voltage relationships on the secondary side of the power transformer. Therefore, with sets composed of a generator and a power transformer it is good practice to connect the voltage relay of the excitation forcing device on the HT (secondary) side of the power transformer or to the generator voltage which is current-compensated to the value of the secondary voltage of the power transformer.

If the circuit of an excitation forcing device uses only one voltage relay connected to one group of instrument transformers, then special consideration should be given to preventing false operation of the device due to blown fuses or short-circuits in the voltage measuring circuits. False operation of the forcing system results in a reactive current overload of the generator which is an unpermissible fact.

Sometimes the voltage relay is connected to a separate voltage transformer which is used only by the excitation regulating device and it has no fuses and circuit breakers in the measuring circuits. The circuits of the excitation forcing devices can be also controlled by blocking blown fuses in a way similar to the remote-control protection of transmission lines.

To improve the efficiency of the excitation forcing devices, the voltage relays are connected to a forward sequence voltage filter (Fig. 1-6*a*). Often this

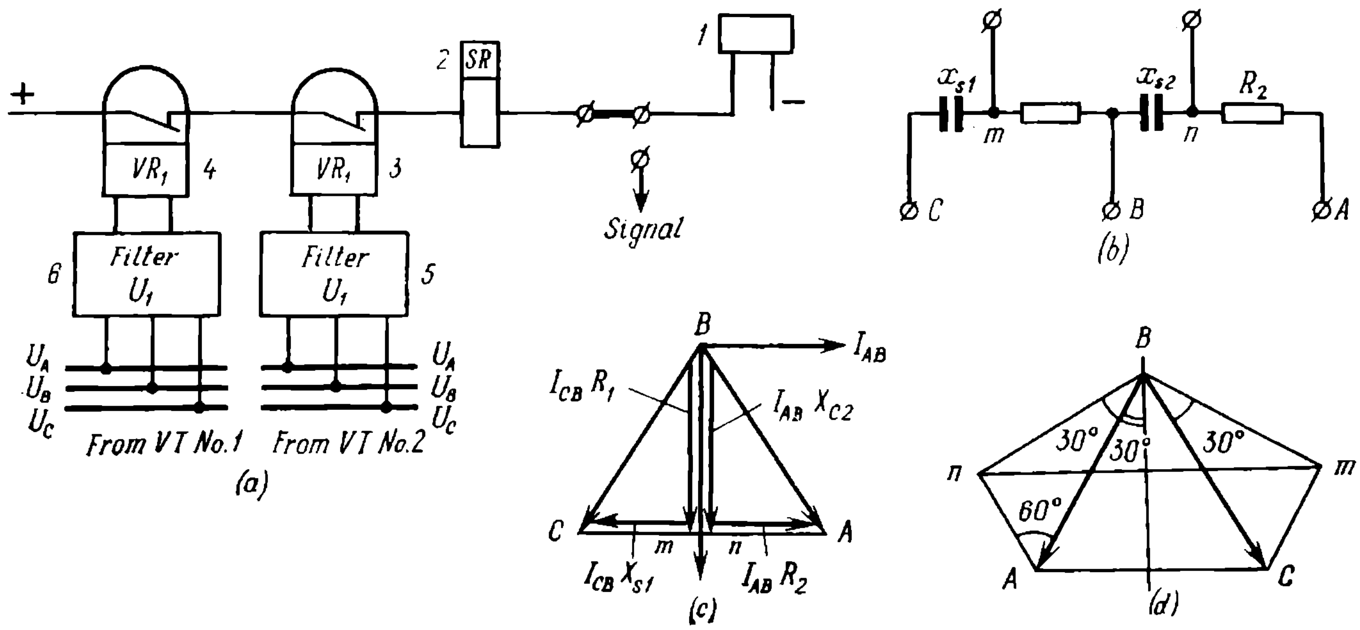


Fig. 1-6. Excitation forcing with the aid of relay connected through forward-sequence filter

(*a*) excitation forcing circuit; (*b*) internal connections of filter; (*c*) diagram showing application of backward-sequence voltage to filter; (*d*) diagram showing application of forward-sequence voltage to filter

filter is of the resistance-capacitance type (Fig. 1-6*b*). Shown in the Figure are also potential diagrams of the filter, when it is at the forward and backward-sequence voltages.

It is clear from the diagram that if the impedance of the filter arms satisfies the condition

$$R_1 : x_{C1} = x_{C2} : R_2 = \frac{\sqrt{3}}{2} : \frac{1}{2} \qquad (1\text{-}9)$$

the filter output voltage at the positive phase sequence is 150 per cent of the rated interphase voltage.

The excitation forcing device must be furnished with switches to allow attending personnel to remove the device from operation. Because of the simple construction of the relay-type excitation forcing system, its application is likely to be useful for all generators and synchronous capacitors, whatever the automatic excitation regulation devices employed by these machines.

1-3. Excitation Compounding with Cumulative Connection of Electromagnetic Voltage Corrector

Generator compounding, i.e., changing the current flow in the field coil as dictated by the current flow in the stator with a view to improving the generator external characteristic is accomplished by rectifying and adding to the field current (Fig. 1-7) a current proportional to the stator current.

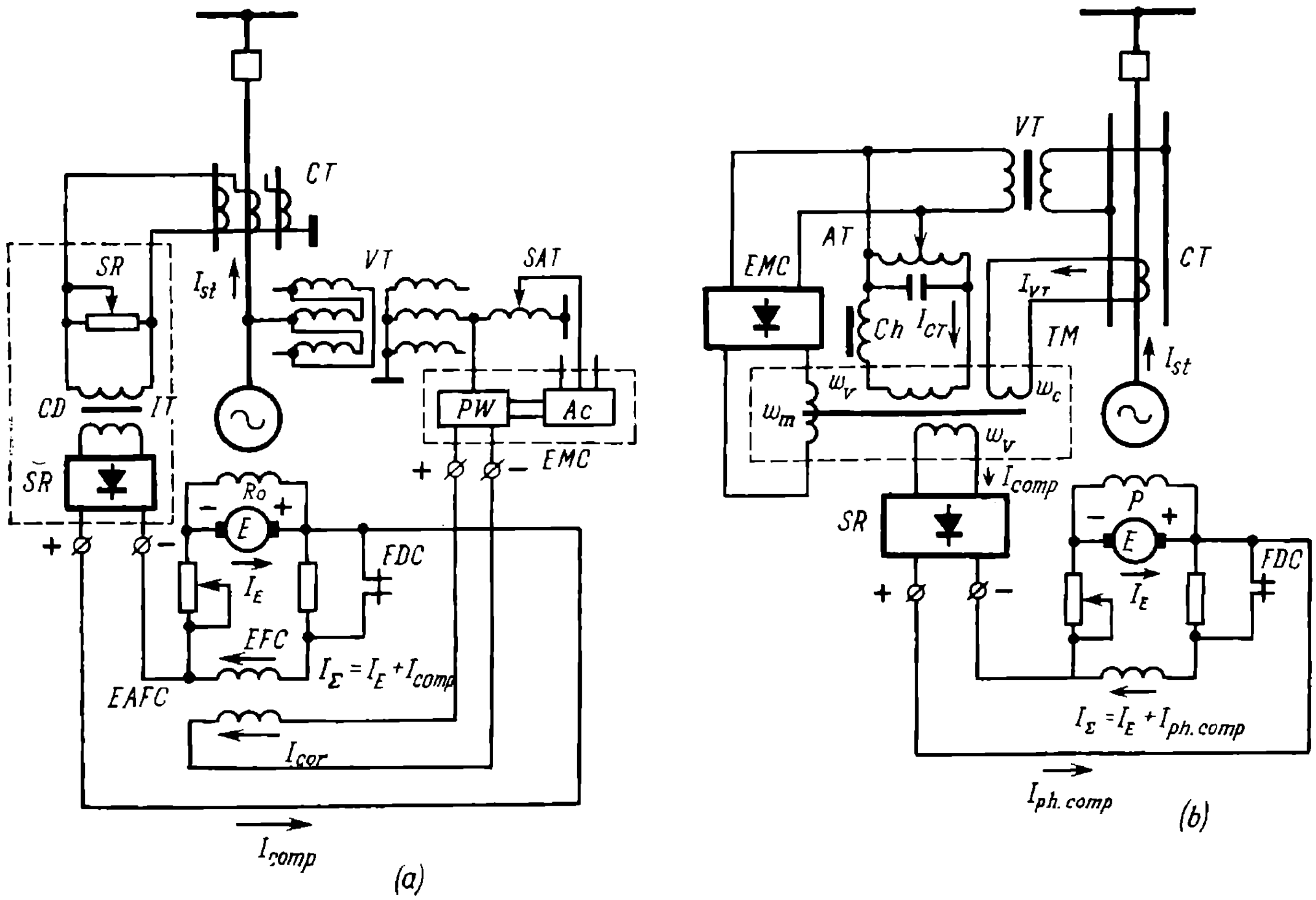


Fig. 1-7. Compounding device principle
(*a*) full current compounding; (*b*) phase compounding

With combined use of a compounding device and an electromagnetic voltage corrector, two systems for excitation compounding of generators may be employed. These are *full current compounding* and *phase compounding*. In the case of full current compounding the actions proportional to the stator current and the generator voltage fed from the instrument current and voltage transformers are summed up after rectification of the currents. In the case of phase compounding this is done before rectification of the currents, i.e., on the a.c. side, which allows the effect of the phase angle between the stator current and the voltage to be taken into account.

As compared to the full current compounding device, the phase compounding device maintains the generator terminal voltage more precisely. More than that, the voltage corrector intended for holding the specified voltage level uses significantly smaller power.

Widely used for excitation regulation are excitation controllers with controlled phase compounding. Let us consider the action of this device in more detail. With no compounding and with the resistance of the stator windings neglected, the voltage across the generator terminals in conformity with Fig. 1-2*a*

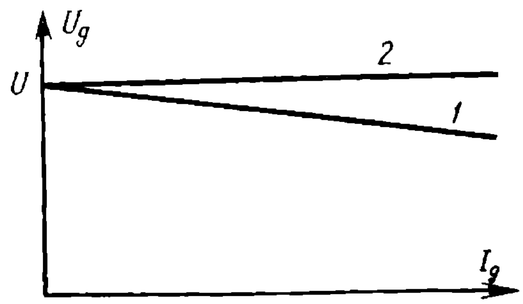


Fig. 1-8. External characteristics of generator

$$\dot{U}_g = \dot{E}_g - jx_g\dot{I}_g \tag{1-10}$$

If the emf and the value of x_g are constant, the external characteristic of the generator is determined by the straight line *1* in Fig. 1-8. The voltage decreases with an increase in the stator current. To keep the voltage constant (line *2*), the control device must be able to increase the emf by

$$\Delta\dot{E} = jx_g\dot{I}_g \tag{1-11}$$

The additional emf must lead the stator current vector by 90 degrees, i.e., it must depend both on the phase and the value of the stator current (Fig. 1-9*a*). [In full-current compounding devices this requirement is not met, since the generator emf increases equally regardless of the phase current. The result is that the voltage sometimes exceeds the rating and sometimes fails to recover to the rating (Fig. 1-9*b*). The specified voltage is maintained by a voltage corrector which should have a sufficiently high power.]

With phase compounding devices, voltage correction is effected through varying the transformation ratio of the intermediate summation transformer by magnetizing its core with the rectified current from the voltage instrument transformer. The voltage correction degree depends on the level of the voltage across the terminals of the voltage transformer and its accomplishing requires only minute power. Owing to this the device is called a controlled phase compounding device.

The complete diagram of a voltage regulator is shown in Fig. 1-10[1-4]. The principal element (power element) of the device is a transformer with magnetization (*TM*) which represents a transformer-coupled magnetic amplifier with two supply windings. The primary series winding is connected to current transformers *CT*. The primary parallel winding is supplied from voltage transformer *VT* through step-up autotransformer *AT* and ballast resistance in the form of a reactance coil *RC*.

As shown in Fig. 1-10 the current transformers are connected to phases *A* and *C* and the current in the series winding *T* equals the vector difference between the secondary currents of these phases. The current in the winding *T*

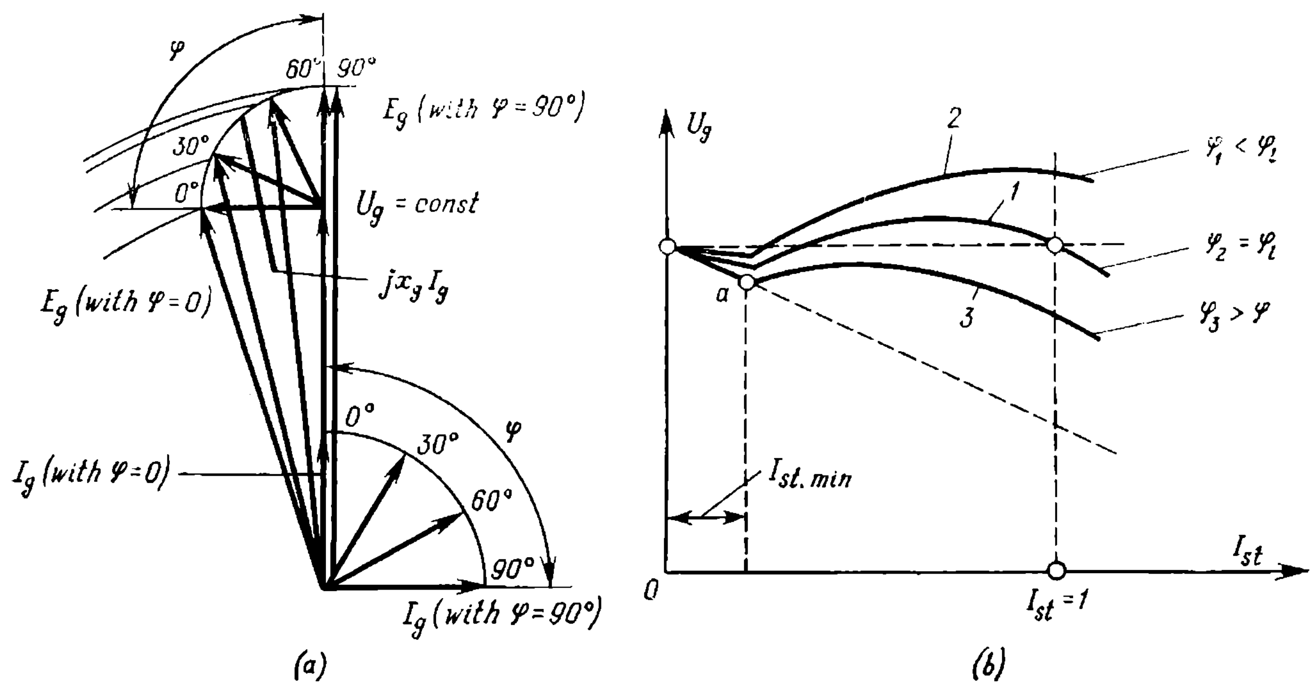


Fig. 1-9. Characteristics of compounded generator
(a) generator emf E_g versus load angle φ when U_g is constant; (b) external characteristics of generator compounded by full current with different cos φ; point a stands for the compounding threshold

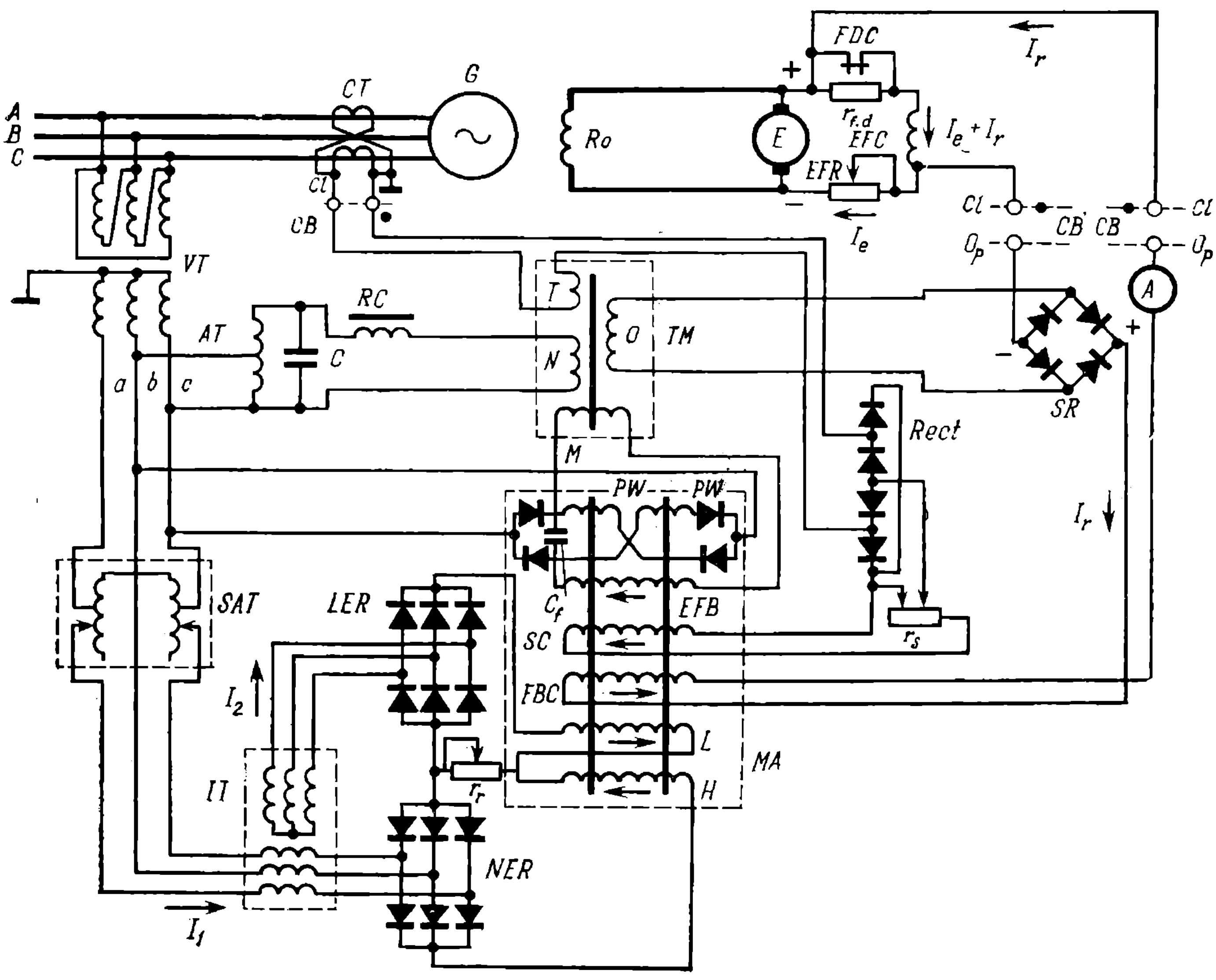


Fig. 1-10. AEC circuit with controlled phase compounding

of transformer *TM* must have such a value that when angle φ between the *A* phase current of the generator and the same phase voltage U_{AO} is equal to 0, the current in the *T* winding leads the current in the *N* winding by 90 degrees. The above-mentioned requirement is met by connecting the autotransformer *AT* to the voltage U_{BC} developed across the secondary windings of the voltage instrument transformer with delta-star connection of the windings.

The reactance coil (*RC*) makes the current in the winding *N* linearly dependent on the voltage imposed. The reactance coil is intended to accomplish the

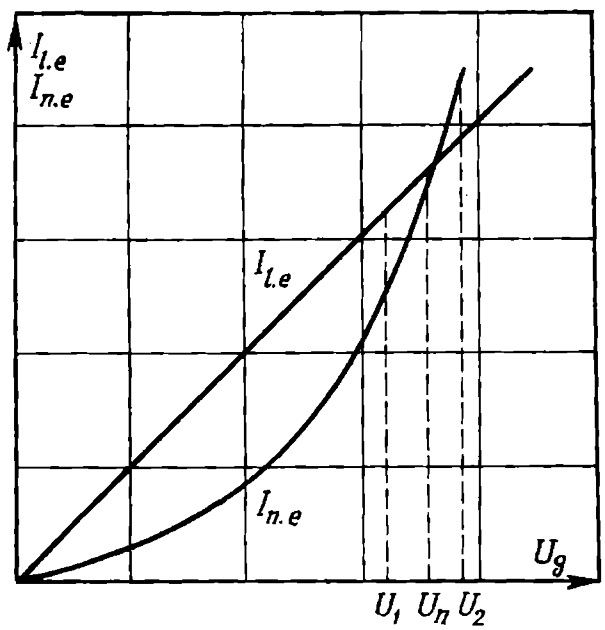


Fig. 1-11. Characteristic of AEC measuring element

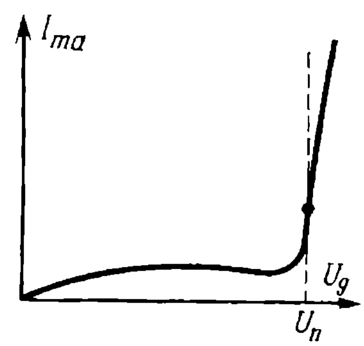


Fig. 1-12. Characteristic of magnetic amplifier in controlled phase compounding device

regulation at no-load and small-load of the generator, when the influence of the winding *T* is small. The autotransformer *AT* increases the reactance coil supply voltage so that the impedance of the coil is raised which ensures proportionality between the current in the circuit and the voltage. In addition, such a voltage increase materially decreases the capacitance of the compensating capacitor *C* used to decrease the load imposed upon the voltage transformers.

For biasing the transformer *TM*, use is made of a control winding connected to the output of the magnetic amplifier *MA* fed by the rectified current from the voltage transformer. The intermediate amplifier is controlled from a three-phase measuring element and together with it makes up the voltage corrector.

The measuring element *IT* has two windings. These are a primary winding used as a non-linear element which feeds power to one of the magnetic amplifier windings (winding *N*) through the non-linear element rectifiers *NER* and a secondary winding feeding the *MA* winding *L* (linear element) via the rectifiers *LER*. The resultant effect produced by the magnetic fluxes caused by the currents I_1 and I_2 in the magnetic amplifier is determined by the current dif-

ference $I_{l.e} = I_2$ and $I_{n.e} = I_1$ (Fig. 1-11). When the voltage exceeds the specified value due to biasing of the core of instrument transformer IT, the nonlinearity of the current I_1 abruptly rises and thus the characteristic of the magnetic amplifier attains the form shown in Fig. 1-12. Accordingly, the output current characteristics of the regulator (Fig. 1-13) ensure the forcing action in the regions close to the voltage U_l which the regulator must maintain.

The regulating resistor r_r (Fig. 1-10) is used to shift the characteristic of the magnetic amplifier MA towards the region of the desired voltages. This resistance is connected in series with the linear and nonlinear windings of the instrument transformer IT. The voltage setting maintained by the regulator is assigned by the setting autotransformer SAT feeding power to the instrument transformer IT. The voltage rating is varied by 10 to 15%. The setting is controlled manually or by remote control.

To control the steepness of the output current characteristic of the voltage corrector, the magnetic amplifier MA employs external feedback (EFB) windings. One of the EFB windings is fed with the output current from the transformer TM (from the winding O and rectifiers SR), i.e., with the current flowing in the excitation winding of the exciter. The other winding SC is fed with the stator rectified current whose value is controlled by the resistors r_s.

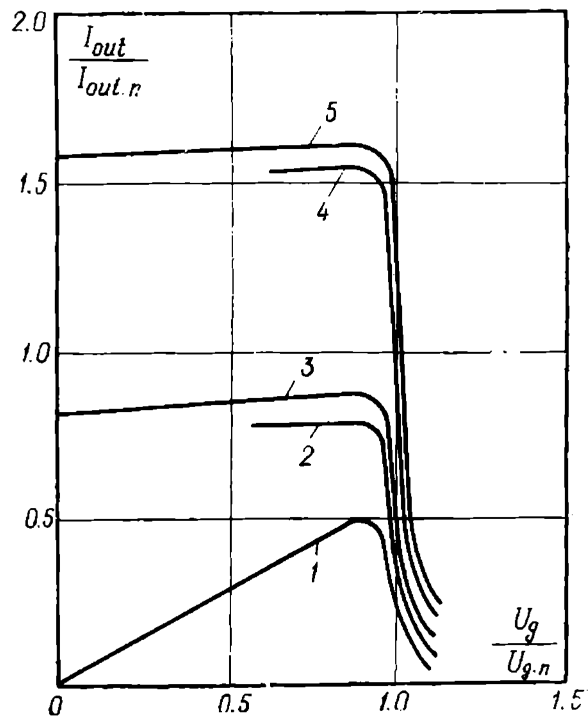


Fig. 1-13. Output current of excitation regulator with controlled phase compounding versus generator voltage

1 — no-load operation of generator; 2 — 50% generator load with cos φ close to 1; 3 — the same with cos φ close to 0; 4 — 100% generator load with cos φ close to 1; 5 — the same with cos φ close to 0

The 20-μF capacitor connected to the output of the autotransformer AT allows the total load of the voltage transformer to be reduced about 2 times. The filter capacitor C_f, capacity of 80 μF, at the output of the magnetic amplifier improves the performance of the corrector.

The AEC device can be placed into the excitation circuit either by connecting to the common parallel winding in the manner shown in Fig. 1-10 or to a separate exciting winding. When the use is made of a separate exciting winding, a minimum output is required from the AEC device.

The voltage maintained by the AEC device is dependent on the frequency. One per cent variation of the frequency makes the voltage vary by 1.0 to 1.5 per cent. The maximum output power is about 650 W. At the 20-μF capacitance of the capacitor (C_c = 20 μF) the maximum feed current from the three-phase group of transformers does not exceed 4.0 A in two phases and is 1.0 A in the third phase. At the maximum AEC power the voltage across the current transformers is about 200 volts. This voltage decreases when decreasing output power

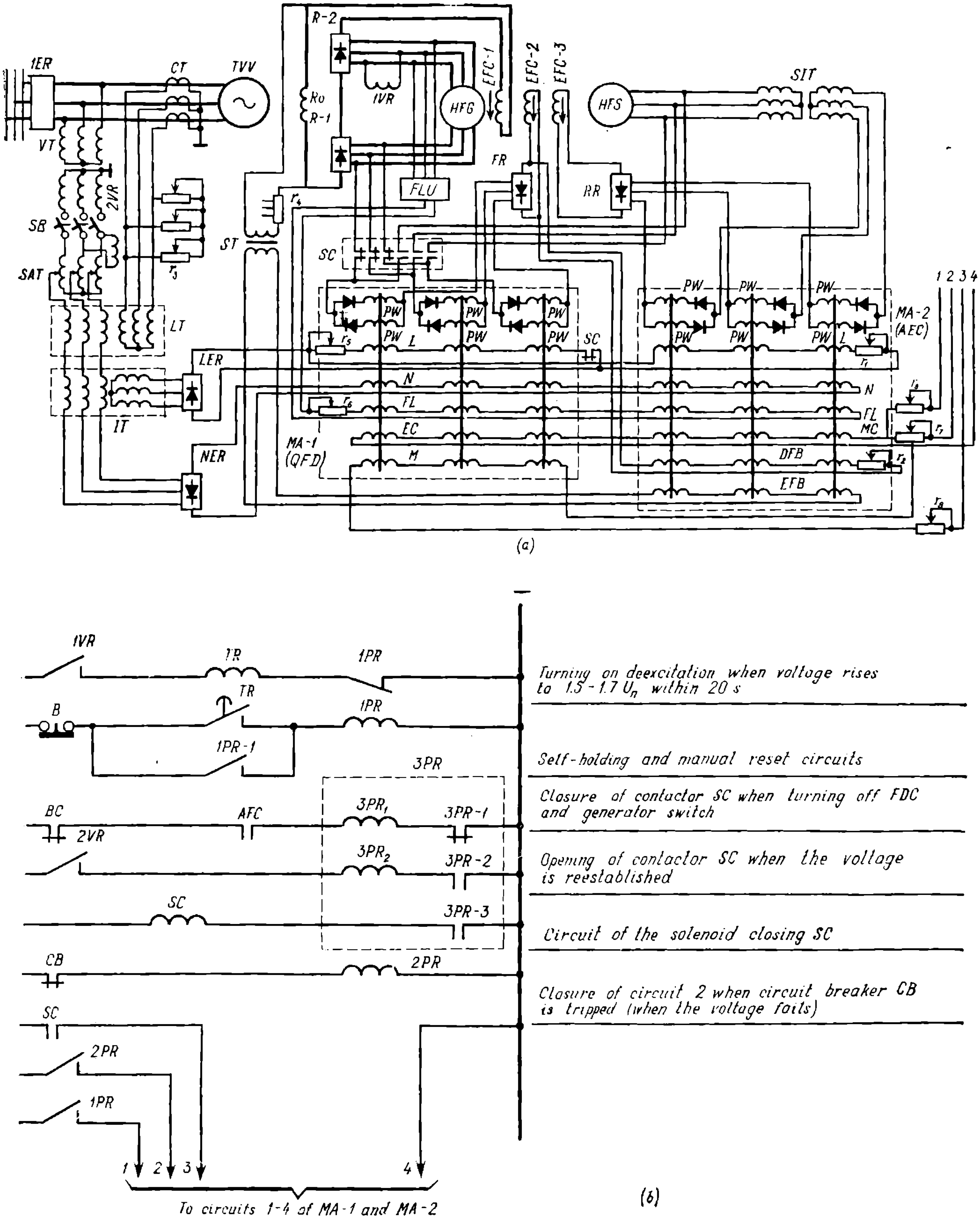


Fig. 1-14. AEC and excitation forcing devices, type ЭПА-325Б for high-frequency excitation generators, series ТВВ-150 and ТВВ-300

(a) schematic diagram; (b) variant of automatic switching for starting period

of the device. The output power capacity of the device is sufficient to ensure the regulation of the voltage of the generators whose exciters have an excitation power not above 1,000 kW at the rated load of the generators. When use is made of greater excitation powers, two sets of *EAC* devices must be employed, an example being hydraulic generators equipped with exciters whose field power ranges from 1,000 to 2,000 kW. One voltage corrector which is connected to the series-connected control coils of two *TM* transformers may be used in this event.

1-4. Excitation Controllers of Generators, Series TVV, with a High-Frequency Excitation System

The TVV series generators with a high-frequency excitation system are furnished with excitation control devices, type EPA-325B (ЭПА-325Б) (Fig. 1-14)[1-4]. This device includes an automatic excitation controller (*AEC*) of the proportional type, quick-action excitation forcing device (*QFD*) and a forcing limiter unit (*FLU*).

The rotor winding *Ro* is supplied with a rectified current from the high-frequency generator *HFG* having three field (excitation) windings: *EFC-1* (exciter field coil *1*) connected in series with the rotor winding of the main generator; *EFC-2* used to ensure the forcing effect and supplied from the *MA-1* magnetic amplifier, its output current being small at the normal voltage across the stator terminals of the *TVV* main generator with an abrupt increase in it, when the voltage decreases; and *EFC-3* connected in opposition to the *EFC-1* and *EFC-2* coils.

The *EFC-3* coil is connected to the *MA-2* amplifier of the *AEC* device. The field built up by the *EFC-1* coil exceeds the value needed for normal operation of the *HFC* generator, the excessive amount of field being compensated for by the effect of current flowing in the *EFC-3* coil.

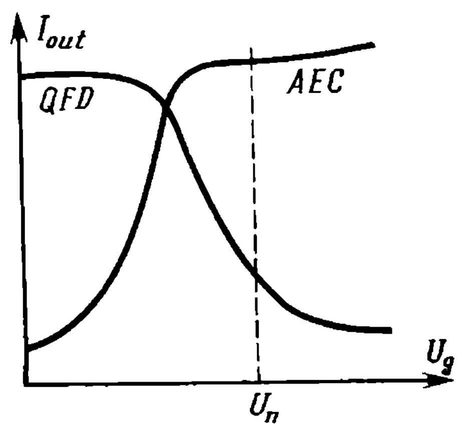


Fig. 1-15. Characteristics of AEC and QFD devices in ЭПА-325Б

Figure 1-15 shows the output current characteristics of the magnetic amplifiers employed by the automatic excitation control and quick-action excitation forcing devices (*AEC* and *QFD*). Any drop in the terminal voltage of the *TVV* generator decreases the output current of the magnetic amplifier *MA-2*. The result is a reduction of the compensating effect of the *EFC-3* coil and an increase in the effect of the current flow in the *EFC-1* coil. The reverse of this process takes place when the terminal voltage of the generator rises. If the generator voltage drops by a considerable value, the current in the *EFC-3* coil abruptly lowers with resultant increase of the voltage across the high-frequency generator (*HFC*). The current in the *EFC-1* coil sharply rises to force the excitation of the generator (to raise the current in the excitation winding *Ro*).

The *LT* transformer and *IT* saturable transformer are connected into the *full-current compounding circuit*. The primary winding of the transformer *IT* serves as a saturable reactance coil forming the non-linear element of the measuring circuit (*NER*). The secondary winding of the transformer *IT* forms the linear element of the measuring circuit (*LER*). The rectified currents of the linear and non-linear elements are fed to the control coils *L* and *N* of the magnetic amplifiers *MA-1* and *MA-2*. The characteristics of the linear and non-linear elements look like those shown in Fig. 1-11. One of the coils of the magnetic amplifier *MA-2* ensures the direct feedback (*DFB*). The coil is supplied with the current flowing in the *EFC-2* coil from the excitation forcing device (*QFD*). It is cumulatively connected with the winding *N* of the non-linear element. The use of direct feedback compensates for the magnetization effect of the magnetic amplifier *MA-2*, caused by the current from the controller measuring

element when drops occur in the terminal voltage of the main generator. To make the control stable, use is made of elastic feedback (*EFB*). The *EFB* coil is supplied with exciter current via the *ST* transformer. Resistors r_1 — r_6 are setting resistances used when timing the controller. The device operates as follows.

When the terminal voltage of the *TVV* generator drops below the rated value, the effect of the current in the linear element winding exceeds that of the current in the non-linear element winding. The difference between these effects magnetizes the saturable reactor of the

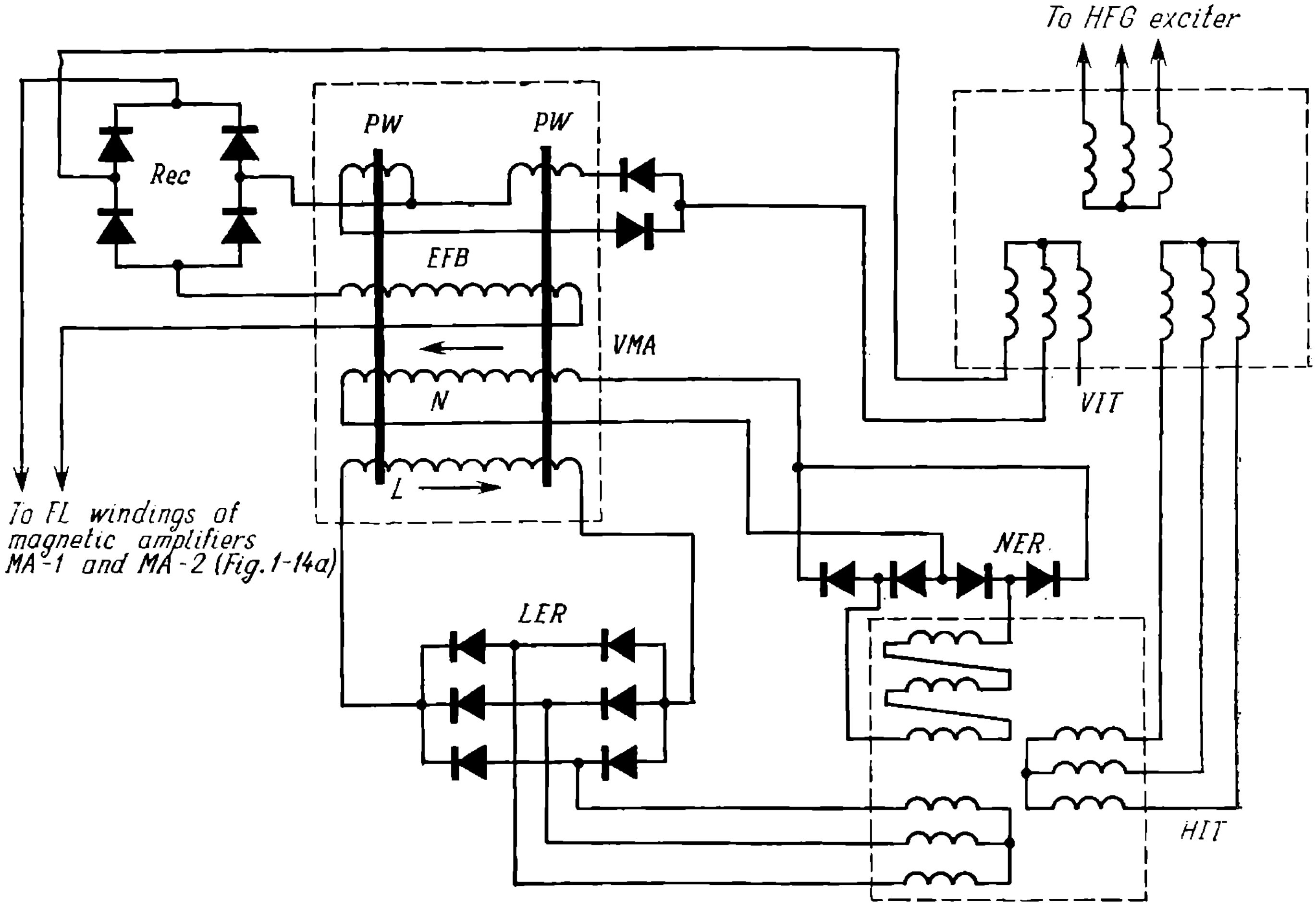


Fig. 1-16. Excitation forcing limiter of ЭПА-325Б device

magnetic amplifier *MA-2* and, if there were no direct feedback, the voltage decrease would continue. The *DFB* coil is connected in parallel with the *EFC-2* coil. When the voltage decreases, the currents in the *EFC-2* and *DFB* windings tend to rise due to the action of the *QFD* device (owing to the rise in the current from the power (load) windings (*PW*) of the magnetic amplifier *MA-1*). The rise of the current flow in the *DFB* coil of the magnetic amplifier *MA-2* causes an increase in the impedance of its power (load) windings (*PW*) and abruptly reduces the current in the *EFC-3* coil, which ensures the required forcing effect.

When the voltage increases above the rating, the output current of the *MA-1* of the quick-action forcing device (*QFD*) does not rise, for which reason the increased current flow in the *EFC-3* coil ensures the required regulating effect, i.e., reduces the terminal voltage of the *TVV* generator.

To improve the forcing effect, the power (load) windings of the magnetic amplifier *MA-1* are supplied from the high-frequency generator *HFG*, whose voltage rises in the process of forcing to produce a positive feedback effect, i.e., to provide additional gain. When starting, the contactor *SC* changes over the *MA-1* power windings to be supplied from the high-

frequency subexciter *HFS*. The power windings of the *MA-2* amplifier are constantly supplied by the high-frequency subexciter via the interventing transformer *SIT*.

The contactor is controlled manually or automatically when the field discharge control (*FDC*) is closed. Fig. 1-14*b* shows the automatic version. Turning on the automatic field discharge control (*FDC*) applies voltage to one of the coils of the two-position relay *3PR* by which the circuit of the *SC* contactor is closed. The latter contactor changes over the *MA-1* power windings to *HFS*, closes the additional magnetizing winding *M* (through the adjusting resistor r_9) and opens the circuit of winding *L* of the excitation forcing device. Since in this case the effect of the current in the *EFC-2* coil overcomes the effect of the current in the *EFC-3* coil, flowing from the *AEC* (from the magnetic amplifier *MA-2*), a current appears in the rotor winding *R* and in the *EFC-1* coil. After a voltage has appeared across the *TVV* generator terminals, the voltage relay *2VR* whose setting $U_f = U_n$ functions. The other coil of the two-position relay *3PR* which resets and opens the circuit of the *SC* contactor is closed. The above-mentioned opening of the linear element circuit when starting the generator is necessary to limit the voltage across the *HFG* under the starting conditions to 0.5 of the nominal value.

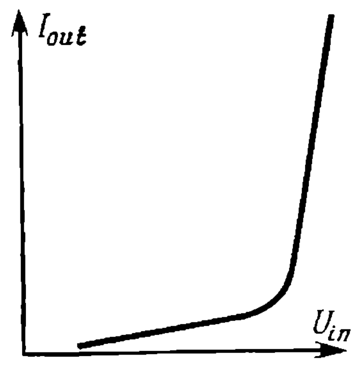


Fig. 1-17. Characteristics of excitation forcing limiter used in ЭПА-325Б device

The ЭПА-325Б regulator assembly incorporates an excitation forcing limiter and deexcitation units. The excitation forcing limiter employs magnetic elements with the *VIT* instrument transformer connected to the terminals of the *HFG* generator (Fig. 1-16). When the voltage is twice the value dangerous to the device rectifiers, the output current of the *VMA* abruptly rises. Through the circuit of the *FL* winding, this current causes a decrease in the output current of the magnetic amplifier *MA-1* and increases the output current of the magnetic amplifier *MA-2* (Fig. 1-14) with a resultant abrupt decrease in the forcing current. The degree of limiting, i.e., the change in the characteristics steepness (Fig. 1-17) is controlled by the internal feedback coil of the magnetic amplifier *VMA* (Fig. 1-16).

When the voltage reaches the value of 1.5 to 1.7 U_n (due to the controller being at fault or to some other cause), deexcitation is accomplished by the *1VR* relay set to $U_f = (1.5$ to $1.7) U_n$ and the time relay *TR* with 20-s operating time. The time relay contacts close the relay *1PR*. The latter remains picked-up and closes the circuit of the deexcitation winding *DC* and magnetizing coil *MC* of the magnetic amplifiers *MA-1* and *MA-2* (Fig. 1-14). The current flow in these windings is controlled by the resistor r_8. The device is reset by the attending personnel through operating button *B*.

To prevent forced excitation of the *TVV* generator, when circuit breaker *CB* disconnects the voltage transformers, the circuit shown in Fig. 1-14 also provides for the use of a deexcitation device. The windings *DC* and *MC* are closed by the auxiliary contact of the circuit breaker *CB*, when it trips open, through resistor r_7 with the aid of relay *2PR*. The resistance r_7 is greater than r_8, as with the voltage circuits opened, deexcitation must be attainable at a lower value of the current flowing in the windings *DC* and *MC*.

1-5. Overaction Excitation Controllers

The quick action of the controllers of the type under consideration and the accuracy with which they maintain the controlled variable are attainable not only by accomplishing the control process in compliance with the variations of the value under control, but also with the rate and acceleration of these variations (according to the first and second derivatives). The required control quality is possible with an available excitation system that ensures a high-speed voltage rise across the rotor winding terminals of the generator.

To improve the stability of generators operating in parallel as follows from (1-3) and Fig. 1-2, it would be good practice to accomplish the control process by the angle δ. However, to take measurements of the angle δ between the emf vector of the generator and the voltage vector of the busbars of the receiving system located at a great distance, often calls for the use of telemetering means. The use of remote control equipment for the control purposes complicates the device and lowers operation reliability.

With networks of simple configuration which use, for instance, a generator-transformer-transmission line-receiving system set, the angle δ can be determined with the aid of the so-called phantom diagrams (see Chapter 4) which simulate the impedance from the point of the generator emf application to the point of voltage measurement and to the busbars of the power receiving system (this impedance opposes the stator current, the corresponding voltage drops being vector added to the stator terminal voltage). However, such a measuring technique has not found wide application.

Most often used are overaction excitation controllers which perform the control function by electrical variables dependent upon the angle δ, namely by the value of current in the transmission line and the voltage at the line point under measurement. To make the control process more rapid and stable, the first and the second derivatives of the above-mentioned quantities are introduced into the control equation, or the value of frequency variation and the derivative of this variation, as the frequency variation is proportional to the first derivative of the δ angle variation, while the frequency variation derivative is in proportion to its second derivative.

The mathematical expression defining the control equation may be written as

$$P = k_0 n + k_1 \frac{dn}{dt} + k_2 \frac{dn^2}{dt^2} \tag{1-12}$$

where P = parameter of operation by which the control is performed

n, $\frac{dn}{dt}$ and $\frac{d^2n}{dt}$ = absolute values of the control parameter variation and the first and second derivatives of this variation, respectively

k_0, k_1 and k_2 = control coefficients

The stability region of the control process and its quickness are determined by the chosen coefficients k_0, k_1 and k_2. Introducing the first derivative in the control equation raises the stability and the process speed within certain limits. An increase in the k_0 and k_2 coefficients also adds to the speed of control. Excessively increasing the coefficients may result, however, in overregulation and hunting.

The optimum coefficients are dependent upon the power system configuration and also upon the direction of and relationships between the power flows over the transmission lines connecting the power station, at which the generator excitation control is performed, to the other units of the system.

Figure 1-18 shows the characteristics which determine the margin of stable operation of a controller accomplishing the control operation by the angle δ and its first and the second derivatives for various k_1 and k_2 values. These characte-

ristics are plotted for a generator whose output power is transmitted to a receiving system over a long transmission line. The stable zone of control varies with the value of the initial angle of transmission (δ_0). The control coefficients are selected so that the control process is stable for any value of angle δ_0. When changing over to control by the current and its derivatives or by the voltage and its derivatives, the margin of the control stability varies; however, the character of the process and thus the possibility of choosing the optimum k_1 and k_2 coefficients remain the same (Fig. 1-19).

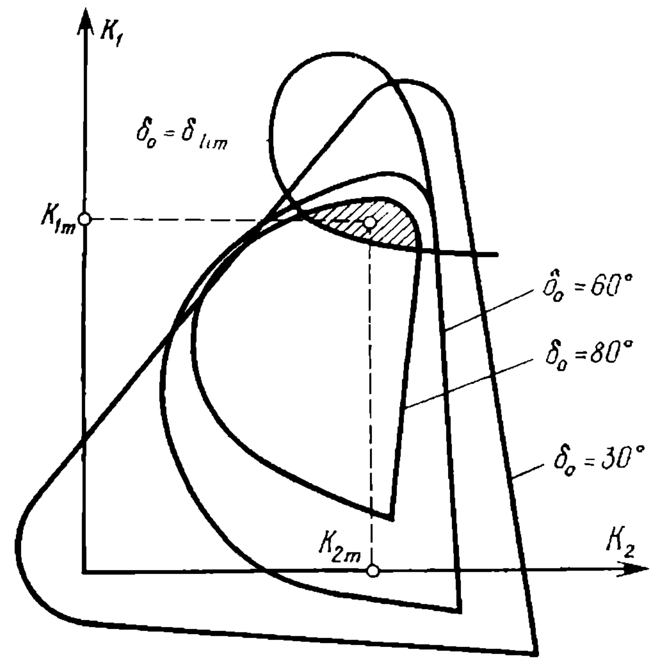


Fig. 1-18. Determining control coefficients k_1 and k_2 depending on power transmission conditions (the region of stable operation is shaded)

k_{1m} and k_{2m} are mean coordinates of points located within the stable operation region

Overaction controllers can be employed both by hydroelectric generators and turbogenerators. In the majority of cases the controllers are used in conjunction with a gas-discharge tube (thyristor) excitation system. As compared with proportional AEC employed by the machines with exciters, the use of overaction AEC on machines furnished with a gas-discharge tube excitation system may raise the steady-state stability limits by 10 to 30 per cent and the transient stability limits, by 6 to 10 per cent.

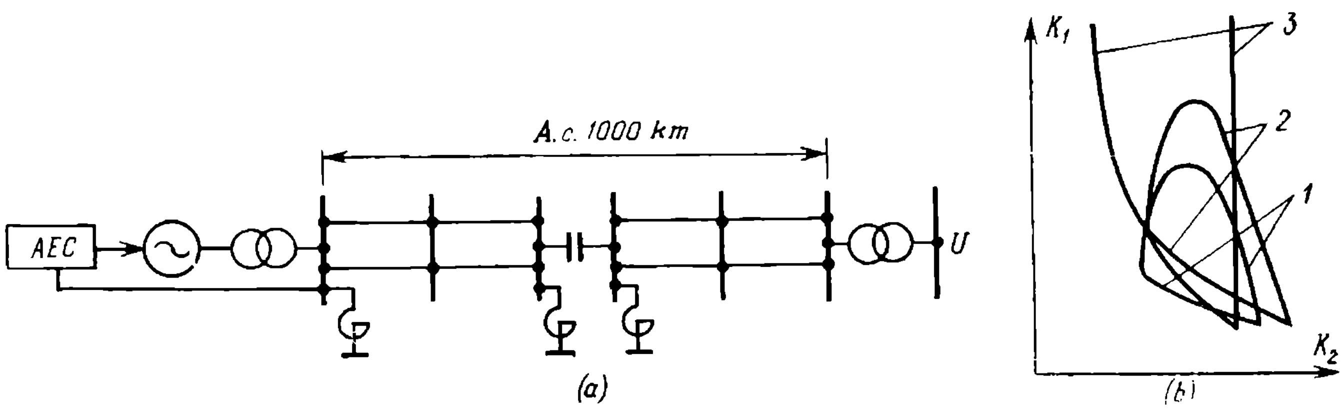


Fig. 1-19. Typical changes in stable control regions with different control coefficients k_1 and k_2

(a) power transmission circuit; (b) boundaries of stable control; 1 — angle δ control; 2 — current control; 3 — voltage control

One model of the overaction controllers developed by the All-Union Electrical Engineering Institute[1-5] provides resultant effects on the excitation system by the following factors:

(a) By the voltage departure ΔU from the rating, with the coefficient

$$k_{\Delta U}=50\frac{\text{excit. unit}}{\text{volt. unit}}$$

(b) By the value of the voltage derivative (by the voltage variation rate) $\frac{dU}{dt}$ with the coefficient

$$k'_{U'}=0 \text{ to } 7\ \frac{\text{excit. unit}}{\text{volt. unit/s}}$$

(c) By the variation of the value of stator current with the coefficient

$$k_I=0 \text{ to } 2\frac{\text{excit. unit}}{\text{cur. unit}}$$

(d) By the value of stator current derivative (by the current variation rate) $\frac{dI}{dt}$ with the coefficient

$$k'_{I'}=0 \text{ to } 8.1\frac{\text{excit. unit}}{\text{cur. unit/s}}$$

(e) By the value of the second stator current derivative (by the current variation rate acceleration) $\frac{d^2I}{dt^2}$ with the coefficient

$$k''_{I''}=0 \text{ to } 1.45\ \frac{\text{excit. unit}}{\text{cur. unit/s}^2}$$

(f) By the value of the rotor current derivative (by the current variation speed) with the coefficient

$$k'_{I'\,rot}=0 \text{ to } 2.7\ \frac{\text{excit. unit}}{\text{rot. cur. unit/s}}$$

The nominal values of current and voltage are assumed as excitation units. The optimum gain factors for various channels are determined for each device by means of precalculation and actual tests in the power systems.

In order to make the external links of the regulator more simple, the effect produced by the frequency and its derivative may be used instead of that produced by the derivative of line current. Experiments on mathematical models have shown, however, that system hunting may occur, when power close in value to the steady-state stability limit is transmitted. In addition, analyses of a series of emergency situations have shown that undesirable falls in the busbar voltage of the station occurred due to the use of frequency channel, when an active power shortage arose at that portion of the power system where the station furnished with a AER was located. Because of this the frequency control channel is mostly used for control of synchronous capacitors.

The overaction controller includes voltage unit *VU*, current compounding unit *CCU* with an intervening current transformer *ICT* and an operational unit *OU* (Fig. 1-20). The voltage unit includes a control motor *CM*, receiver synchro *RB*, differential synchro *DB*, mechanical differential *MD*, rectifier

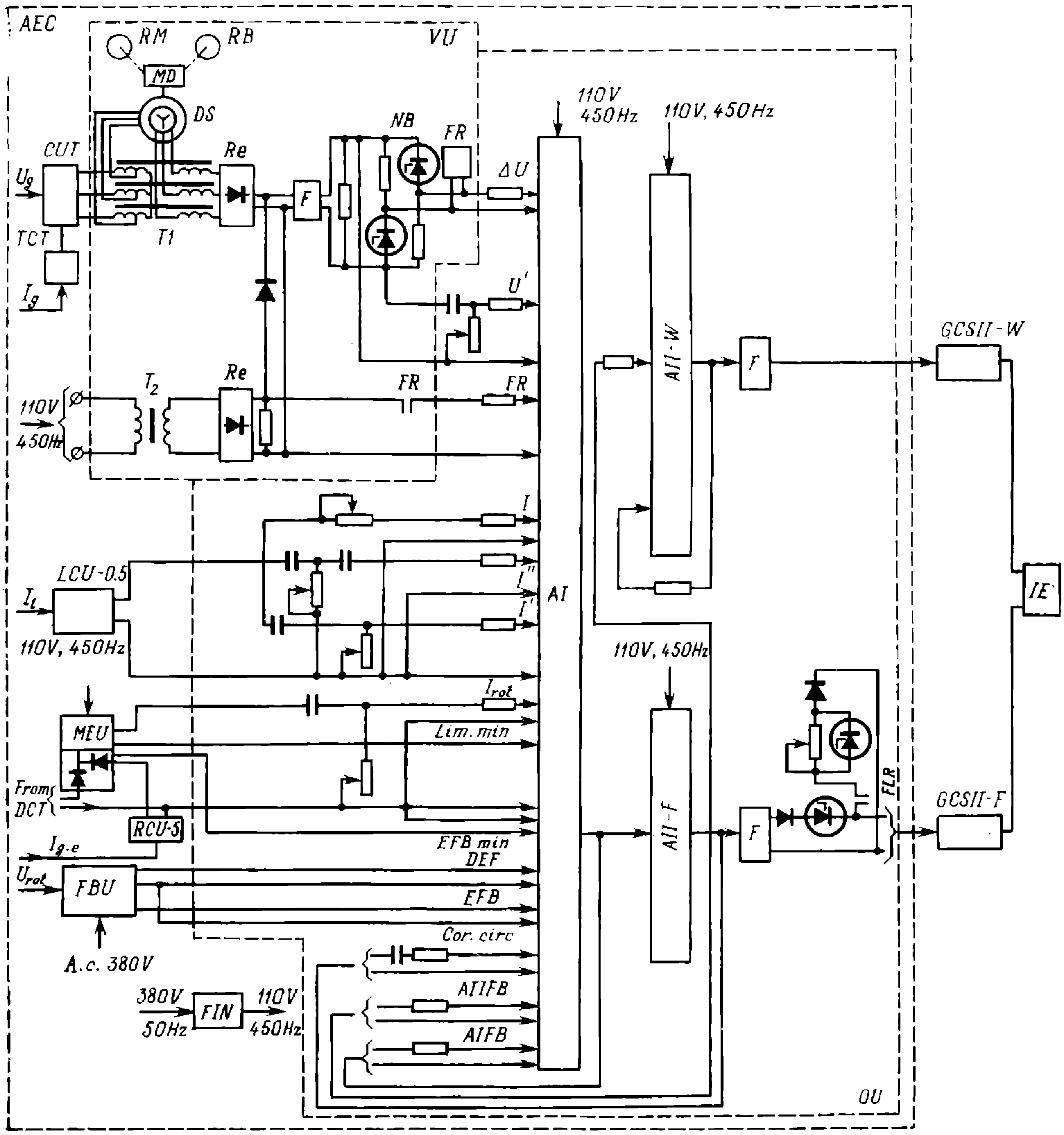


Fig. 1-20. Circuit of overaction AEC. Symbol *FMT* stands for a device used to transform 380 V 50 Hz power into 110 V 450 Hz power

REC, filter *F*, non-linear bridge *NB* employing avalanche diodes, forcing relay *FR* with reset-pickup ratio 0.98, three angle-phase transformers T_1 and backing-up transformer T_2.

The operational unit receives signals from the line current unit *LCU-0.5* (*БТЛ*-0.5), from the rotor current unit *RCU-5* (*БТЛ-5*) the minimum excita-

tion unit *MEU* which is fed from a d.c. transformer (*DCT*), and the feedback unit *FBU* which is acted upon, depending on the value of the exciter voltage U_{rot}.

The output circuits of the operational unit are connected to the windings of the summing magnetic amplifier *AI* which serves as the first amplifier stage. The second amplifier stage is implemented by the magnetic amplifiers *AII-W* and *AII-F*. The power winding current of the *AII-W* amplifier acts upon the semiconductor grid control system of the working group valves *GCSII-W*, while the current of the power winding of the *AII-F* amplifier influences the semiconductor grid control system of the forcing group valves *GCSII-F*. The action is effected through output filters *F* which reduce the a.c. component of the output voltage to 150 mV. Figure 1-21 shows the diagram of the filter.

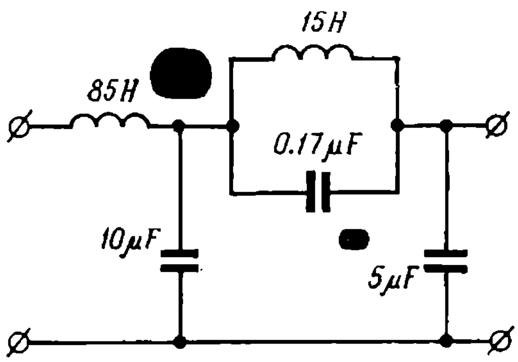


Fig. 1-21. Output filter circuit

Marked *IE* on the structural diagram of the regulator (Fig. 1-20) is gas-discharge tube (ionic) exciter containing two groups of valves, working and forcing. To limit the amount of excitation forcing, the grid supply of the *GCSII-F* forcing group valves is connected via an avalanche diode which is connected to the circuit when the forcing limiter relay *FLR* functions. Due to a forcing relay *FR* having a high reset-to-pickup ratio, the relay functions in case of remote short-circuits in the network. To delay the forcing process after isolating short-circuits (for about 0.1 s), the *FR* uses drop-out delay which is ensured by connecting a capacitor (20 μF) in parallel with the *FR* relay coil. The signal fed to the control coil of the *AI* amplifier from the forcing relay exceeds the deexcitation signal from the current and voltage derivatives. This signal appears when short-circuit faults are isolated. This is done to eliminate the objectionable effect of this signal.

1-6. Conclusions

1. Automatic excitation control of synchronous machines is one of the essential means employed by the automatic power control system to raise the parallel operation stability of electric power stations. Good results issue when generators and synchronous capacitors are well equipped with *AEC* devices.

2. Developed in the Soviet Union are various techniques for controlling the excitation system of synchronous generators. These range from the simple relay forcing method to techniques involving the use of overaction excitation controllers.

3. Proportional excitation controllers which respond to variations of the absolute values of the controlled variable are built mainly in the form of compounding devices with an electromagnetic voltage corrector.

4. Overaction controllers react not only to variations in the absolute values of the variables being controlled, but to its derivatives as well. This adds to the

speed of response and accuracy of the control (regulation) process. The most effective control is by the angle δ and its derivatives. In practice the controllers accomplish control to values dependent upon the angle δ (to current flow in the generator stator or in the line, to the voltage at the network check point and the first and the second derivatives of these quantities). Sometimes the effect of variations to the frequency and the speed of its variation is employed by the control system in place of the effect of the current and voltage derivatives.

5. The performance of the excitation forcing device improves when the forcing output relay reset is delayed for a short period after isolating a power system short-circuit. It is good practice to connect the detecting element of the forcing device to the forward-sequence voltage. With generator-transformer sets, better results are obtained when the voltage relay of the forcing device is supplied from the secondary (higher) voltage side of the power transformer.

6. Exciters employing positive cooling of their windings, must be provided with devices which limit the amount and duration of forcing, and also with de-excitation devices preventing damage to the exciter and the excitation device, in particular to its semiconductor elements, because of intolerable multiplicity and duration of the forcing duty.

1-7. Review Questions

1. Why does the parallel operation stability of synchronous generators increase, when use is made of AEC devices?
2. What is the purpose of relay forcing, when a compounding device with an electromagnetic voltage corrector is used?
3. What is the difference between the proportional type excitation controllers and the overaction controllers?
4. What is the purpose of relay forcing when a controller with controlled phase compounding is used?
5. What are the operating principles of the linear and non-linear elements employed in the measuring components of the voltage regulation devices?
6. What is the influence of synchronous machine excitation controllers on the voltage restoring process after isolating a short-circuit fault?
7. What is the influence of synchronous machine excitation controllers on the short-circuit current damping process?
8. What is the principle of operation of overaction controllers? Explain the purpose of introducing current and voltage derivatives into the control equation.
9. What is the purpose of introducing an elastic feedback from rotor current variations into the control equation?
10. Is it wise to leave the relay forcing system turned on, when the automatic excitation controller is at fault?
11. What is the purpose of resistors r_1 through r_9 in the devices of the EPA-325B (ЭПА-325Б) automatic controllers used for generators furnished with high-frequency exciters (Fig. 1-14)?
12. How is the setting of the voltage relay of the excitation forcing device selected? Why is it desirable for this relay to have a higher reset-to-pickup ratio?
13. What are the actions of attending personnel when operating excitation forcing devices of generators provided with natural and forced cooling of the rotor windings?
14. How can a signal proportional to the derivatives of the variable under measurement be formed?
15. What is the purpose of the individual units employed in the overaction controller designed by the All-Union Electrical Engineering Institute? For the diagram of the controller see Fig. 1-20.

16. Explain why the effectiveness of the overaction excitation control increases when use is made of quick-response excitation systems.

17. What are the advantages and disadvantages of introducing signals dependent on the frequency and the frequency varying rate into the overaction control system?

18. Figure 1-10 shows the diagram of AEC with controlled phase compounding. The device must ensure an automatic increase in the generator rotor current in case of an increase in the angle φ between the current and the voltage of the same phases at the stator end of the generator. The rotor current must be at its maximum at the angle $\varphi = 90$ deg and minimum at the angle $\varphi = 0$ deg. Explain why it is correct to connect the device shown in Fig. 1-10 to the current and potential transformers, if the impedance angle of thè N winding of the transformer TM equals 60 degrees and the T and N windings are opposite-connected [1-4].

Solution. When the vectors of the current and voltage at the stator end of the generator are in phase, they correspond to the vector diagrams in Fig. 1-22*a* for the current, and in Fig. 1-22*b* for the voltage. The current in the T winding of the transformer equals the

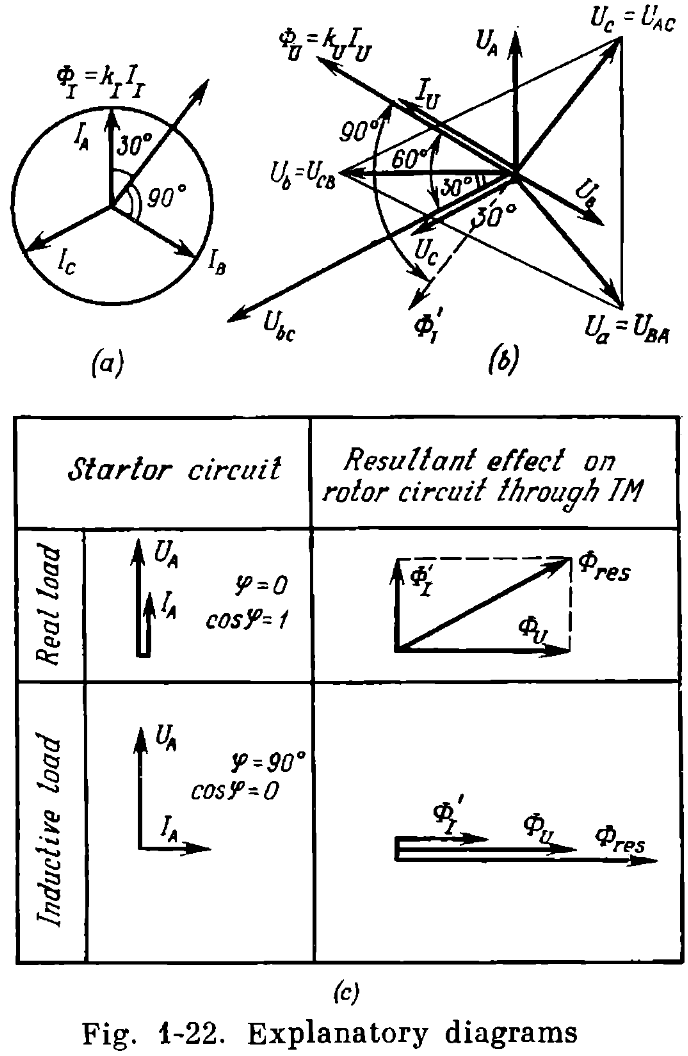


Fig. 1-22. Explanatory diagrams

vector difference between the currents in phase A and phase C. The magnetic flux built up by this current in the T winding is $\dot{\Phi}_T = k_T I_T$. As the T winding is in opposition to the N winding, the flux direction oriented relative to the direction of the flux built up by the current flow in the N winding is of the opposite polarity and is determined in space by the vector $\dot{\Phi}'_T$.

The primary windings of the *VT* transformer are connected to the interphase voltages $\dot{U}_{AB}$, $\dot{U}_{BC}$, and $\dot{U}_{CA}$. These voltages correspond to the voltages $\dot{U}_a$, $\dot{U}_b$, and $\dot{U}_c$ on the star side of the *VT* transformer. The *N* winding of the transformer *TM* is connected to the vector difference between the voltages $\dot{U}_{bc} = \dot{U}_b - \dot{U}_c$. The current $\dot{I}_N$ determining the direction of the flux $\dot{\Phi}_N$ lags the $\dot{U}_{bc}$ voltage vector by 60 deg. It is seen from Fig. 1-22*b* that, as this happens, the flux $\dot{\Phi}_N$ will lag the flux $\dot{\Phi}_T'$ by 90 deg. The resultant flux $\dot{\Phi}_{res}$ (Fig. 1-22*c*) determined by the vector sum of the fluxes $\dot{\Phi}_N$ and $\dot{\Phi}_T$ will be at its minimum. With an increase in the angle φ the absolute value of the flux $\dot{\Phi}_{res}$ rises and will be at its maximum at the angle $\varphi = 90$ deg. It is seen from the diagram in Fig. 1-10 that the rotor current is dependent on the magnitude of the flux Φ_{res} of the *C* winding of the transformer *TM*.

Chapter Two

AUTOMATIC VOLTAGE REGULATION

2-1. General

Maintaining the normal voltage in a power system is one of the basic ways of assuring its proper performance. The State Standard[2-1] specifies that the maximum permitted voltage variation at the load terminals should not exceed ± 5 per cent of the rated value. Voltage drop beyond the specified limits may result in excessive slippage of asynchronous motors with resultant reactive current overload of the feeding elements and decreased luminous efficiency of incandescent lamps where lighting fittings employing such lamps are installed. Fluorescent lamps may even go out if the voltage drops slightly beyond the specified value. An excessive rise in the voltage may cause damage to many incandescent lamps and radio equipment. More than that, an excessive increase in voltage causes premature deterioration of equipment insulation (increases the leakage current) and may result in its failure. Voltage drop at power system node points reduces the capacity of power transmission lines and affects the stability of generators operating in parallel.

The voltage at the check points of a power system is maintained at the rated value through efficient operation of the system on the part of duty personnel (full use of the reactive power of generators and synchronous capacitors, prevention of overloads to the system feeding elements, proper loading and unloading of individual transmission lines and appropriate selection of transformation ratios for step-up and step-down transformers) and also by joint operation of automatic excitation controllers of asynchronous generators and synchronous capacitors, devices which automatically change, when under load, the transformation ratios of power transformers, remote transformer boosters and devices which automatically switch over or continuously vary the capacitive load of static balancers.

2-2. Use of AEC Devices

Automatic excitation controllers are used to maintain the voltage in compliance with the specified characteristic and distribute the reactive load between the power sources under normal operating conditions of power systems. When generators and synchronous capacitors are equipped with AEC apparatus, a change in the required voltage setting is accomplished by special automatic

devices, i.e., voltage controllers or through setting devices operated by attending personnel.

To *decrease* the voltage across the terminals of a generator or a synchronous capacitor a setting autotransformer must be used to raise the voltage supplied to the linear and nonlinear elements of the voltage corrector. In this case the output current of the corrector decreases.

To *increase* the terminal voltage of the generator or synchronous capacitor, the voltage imposed on the linear and nonlinear elements of the voltage corrector must be decreased. This decrease is permissible up to a certain limit

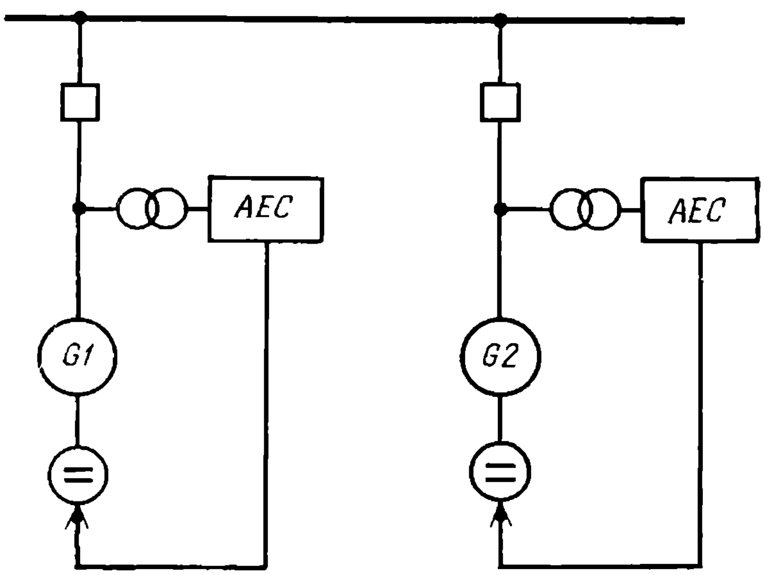


Fig. 2-1. Parallel operation of generators connected into common voltage busbars

dictated by the value of the maximum output current of the voltage corrector. The output current of the corrector is indicated on a control panel instrument.

The problem of voltage and reactive power regulation in a power system, however, cannot be completely solved by the use of AEC devices on generators and synchronous capacitors without intervention by duty personnel. Considered below are some examples which clarify certain principles underlying the use of AEC devices for automating the voltage and reactive power regulation process in power systems.

The generators operate in parallel into the generator voltage busbars. Each generator is furnished with an AEC device. The busbar voltage must be maintained at a specified value (Fig. 2-1).

By convention, the regulation process is considered within a regulating range. For the AEC's, the regulating range is limited by the exciter operation region in which the exciter operates until the field current reaches a value determining a critical excitation amount during the time interval permitted by the exciter design (its electromagnetic and thermal characteristics).

Regulation may be to *astatic* independent characteristics and *static* dependent characteristics. In case of astatic (floating) regulation, the system node voltage by which the regulation is performed is represented by a straight line parallel to the x axis which is the parameter determining the functional dependence, for instance, the reactive component of the stator current $I_{g.react}$ (Fig. 2-2*a*).

Suppose that the generators are furnished with automatic excitation controllers which respond only to the voltage departure from the specified value. When the voltage decreases, it is the AEC with a smaller dead-zone that functions first. The generator equipped with such a controller will start taking on reactive current load. The other parallel machine may not take part in the

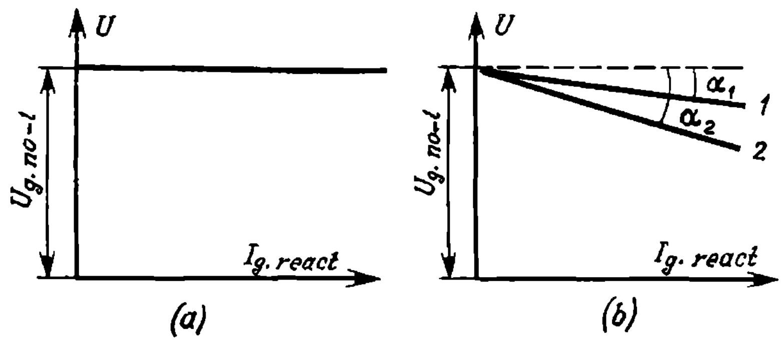


Fig. 2-2. Voltage regulation characteristics
(*a*) astatic (independent) characteristic; (*b*) static (dependent) characteristic

voltage restoration or may participate in it after the regulating capacity of the first generator has been exhausted. Thus, reactive loads are shared by the machines spontaneously.

When use is made of static regulating characteristics (Fig. 2-2*b*) reactive loads are distributed between the machines in compliance with the slope of characteristics $I_{g.react}$ determined by the static coefficients

$$s_i = \tan\alpha_1 \text{ and } s_2 = \tan\alpha_2 \tag{2-1}$$

Loaded with reactive current to a greater degree will be the machine whose voltage regulation characteristic looks more like a straight horizontal line, i.e., the machine having a smaller static coefficient. To change the characteristic slope of $U_g = f\,(I_{g.react})$ and obtain a desirable (stable) distribution of reactive loads between the generators *current stabilization* may be used.

The current stabilization principle is clear from Fig. 2-3. Let the generator be equipped with an excitation controller having an astatic characteristic, the controller's function being to maintain a constant voltage across the stator terminals to which the controller sensing element is connected through an instrument potential transformer. The static control characteristic can be secured in this case, if a stabilized reactive current is fed to the AEC controller. Since the controller tends to hold a constant voltage at the input, this voltage must

automatically follow the equation

$$U_g = U_{no\text{-}l} - I_{g.\,react} s \tag{2-2}$$

where s = required static coefficient
$U_{no\text{-}l}$ = busbar voltage with the generator under no-load

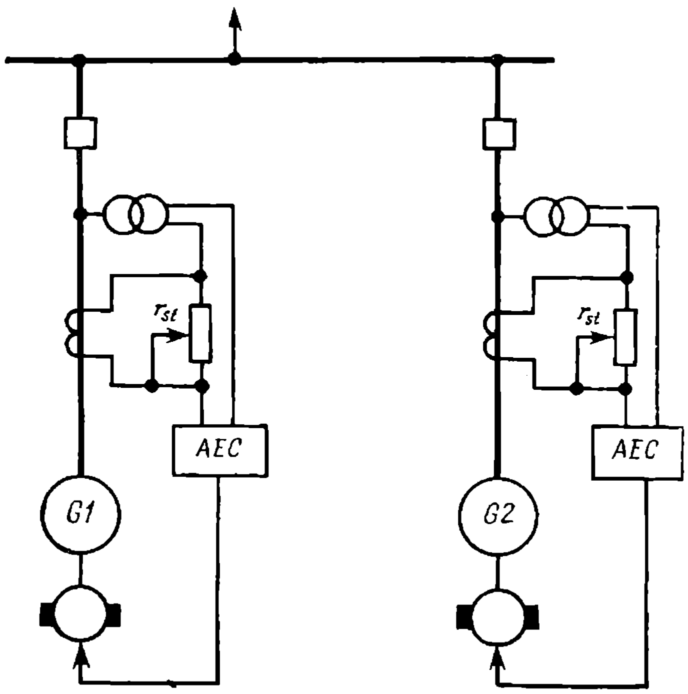


Fig. 2-3. Current stabilization principle

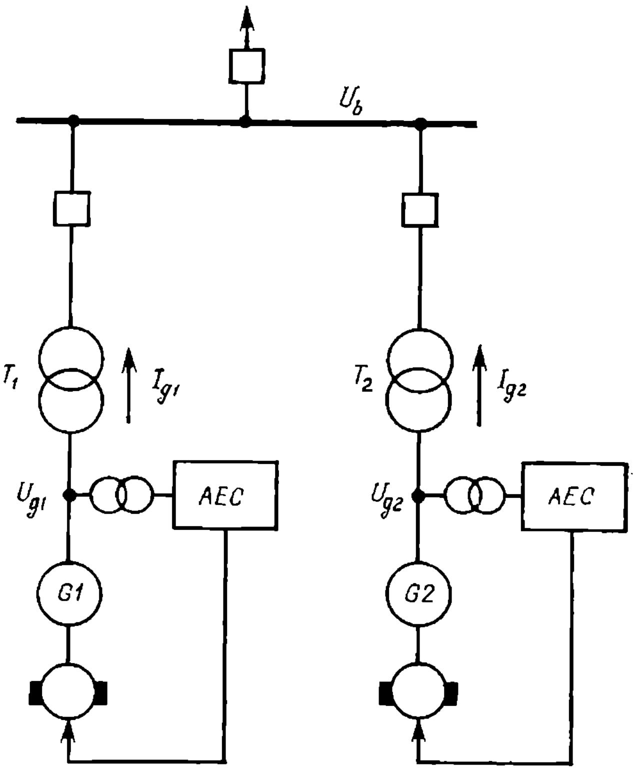


Fig. 2-4. Operation of generator-transformer sets connected into common busbars

The required phase relationships between the voltages and currents applied to the AEC sensing systems can be obtained, if the systems are supplied with voltages as follows

$$\left.\begin{aligned} \dot{U}_{r1} &= \frac{\dot{U}_{AB}}{n_v} - \frac{\dot{I}_C}{n_c} r_{st} \\ \dot{U}_{r2} &= \frac{\dot{U}_{BC}}{n_v} - \frac{\dot{I}_A}{n_c} r_{st} \\ \dot{U}_{r3} &= \frac{\dot{U}_{CA}}{n_v} - \frac{\dot{I}_B}{n_c} r_{st} \end{aligned}\right\} \tag{2-3}$$

where n_c and n_v = transformation ratios of the current and voltage transformers

r_{st} = stabilization resistance

In Fig. 2-2*b* the characteristic slopes are determined by the magnitude $\frac{r_{st}}{n_c} n_v$. The desired sharing of the reactive loads among the generators is obtainable by changing this magnitude.

With full-current compounding devices, the static control $U_g = f(I_{g.\ react})$ is obtained due to the internal static (steady-state) condition of the controller. It is seen from Fig. 1-9*b* that the voltage maintained by the device decreases with an increase in the reactive component of the stator current, which occurs when the value of phase angle φ rises, while the value of the stator full current remains unchanged. When use is made of a voltage corrector, more inertial than the compounding device, the reactive currents undergo some redistribution with time.

The electromagnetic voltage corrector utilizing the circuit shown in Fig. 1-14*a* ensures control according to the expression

$$U = U_{no\text{-}l} - U_{full} s \tag{2-4}$$

The voltage stabilization is dependent on the amount of the full current flowing in the stator coils. To change the static coefficient, an adjustable resistor r_3 is connected in parallel with the winding of isolation transformer *IT* connected to the current transformers *CT*.

In controlled phase compounding devices (Fig. 1-10) the static coefficient is regulated by varying the value of resistance r_s.

The generators operate into common busbars in sets with power transformers. Each generator is furnished with AEC devices. The specified voltage level must be maintained at the collecting busbars (Fig. 2-4). With the system schematically shown in Fig. 2-4 stable sharing of reactive loads by the generator-transformer sets is secured even when the AEC devices connected to the generators output maintain their voltage astatically, i.e., if

$$U_{g1} = U_{g2} = U_{no\text{-}l} = \text{const} \tag{2-5}$$

By neglecting the resistance of the generators and transformers and without taking into account the active component of the load current, i.e., supposing that only a reactive current occurs, the value of this current in phase similar to the voltage phase can be found as follows

$$I_{g1\ react} = \frac{U_{no\text{-}l} - U_b}{x_{t1}} \tag{2-6}$$

and

$$I_{g2\ react} = \frac{U_{no\text{-}l} - U_b}{x_{t2}} \tag{2-7}$$

where x_{t1} and x_{t2} are reactances of transformers *1* and *2*.

From the above-mentioned expressions we obtain

$$\frac{I_{t1}}{I_{t2}} = \frac{x_{t2}}{x_{t1}} \tag{2-8}$$

i.e., with the accepted assumptions the distribution of reactive currents is inversely proportional to that of the reactances of the transformers.

Expressions (2-6) and (2-7) may be presented as follows

$$U_b = U_{no\text{-}l} - x_{t1} I_{g1\,react} \qquad (2\text{-}9)$$

and

$$U_b = U_{no\text{-}l} - x_{t2} I_{g2\,react} \qquad (2\text{-}10)$$

These relationships correspond to the steady-state characteristics of the control process.

The redistribution of reactive loads is obtained by adjusting the static coefficient, when installing AEC's which have static (steady-state) characteristics.

Use of AEC's to maintain the voltage constant at a remote point in the power system. Sometimes it is necessary to maintain a constant voltage at a remote point in the power system rather than across the generator busbars, for instance across higher voltage busbars of step-up transformers or at the end of the transmission line utilizing a generator-transformer set. In these instances the voltages of the point at which the voltage regulation must be performed should be fed to the AEC sensing element. As mentioned previously, a remote end voltage can be measured with the aid of a phantom circuit.

If the impedance of the network section from the AEC location to the point where the automatic voltage regulation must be performed is denoted z_{net}, while the terminal voltage of the instrument voltage transformer to which the AEC sensing element is connected is designated as $\dot{U}_{gen}$ and the current flow in the same phase as $\dot{I}_{st}$, then this phase voltage at the receiving side is

$$\dot{U}_b = \dot{U}_{gen} - \dot{I}_{st} z_{net} \qquad (2\text{-}11)$$

Hence

$$\dot{U}_{reg} = \dot{U}_{gen} = \dot{U}_b + \dot{I}_{st} z_{net} \qquad (2\text{-}12)$$

To carry into effect the method of compensation for the voltage drop due to the current flow in the equivalent resistor of the phantom circuit, use may be made of the AEC elements employed for current stabilization with a change in the connection polarity of the current circuits. In a number of cases compensation is provided only for the voltage drop due to the reactive component of the full current through the inductive reactance of the circuit formed by the generator and the substation busbars the voltage across which must be regulated.

2-3. Group Control of Generator Excitation

The centralized control of the power system operation presupposes that the operation of individual power stations follows a prescribed routine in compliance with a 24-hour schedule of voltages and loads (active and reactive) specified by the dispatching department. The work of attending personnel on maintaining the voltage at a specified level amounts to operating the setting controls of

the AEC devices in due time. With compounding devices having a voltage corrector, attending personnel change the transformation ratio of the setting autotransformer.

If there are many power units operating in parallel at the electric power station, the excitation control task of attending personnel becomes a time-consuming one. In this case it is expedient to use devices which enable personnel to control the excitation of a group of machines in one operation without overloading individual generators and transformers, when placing the machines under load. If such a group control is put into practice or planned, the next

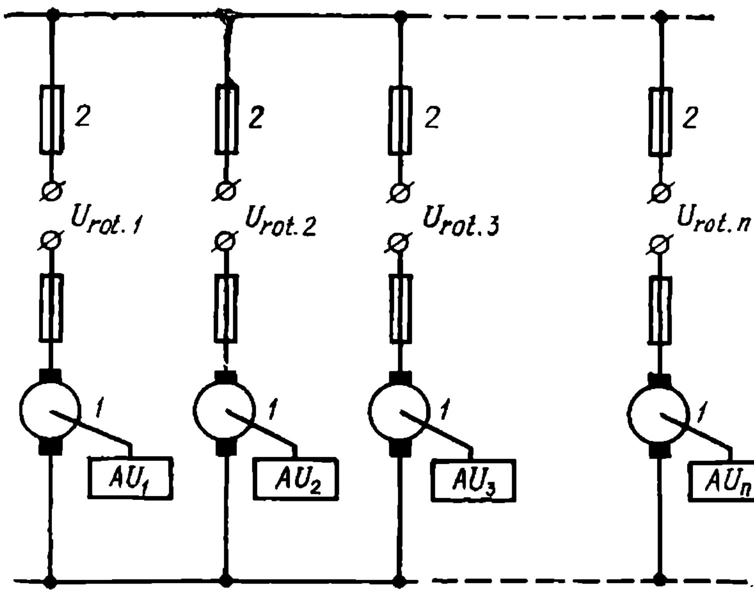


Fig. 2-5. Equalizing reactive loads of synchronous machines

step in the automation of a voltage regulation process is the use of a central voltage controller which eliminates the operator's intervention in the operation of AEC devices when the power station follows its specified voltage schedule. It is clear that such devices may find wide application at automated multi-unit hydroelectric generating stations.

In addition to simple design and trouble-free operation the essential requirements placed on the group excitation control devices are as follows:

(a) The generators must share the reactive loads as prescribed in the schedule and in an aperiodic manner, i.e., without the appearance of hunting between the machines connected to the group regulation system.

(b) Provision should be made for disconnecting any machine from the group regulation systems for manual regulation. When automatically disconnected from the network, the generator must be automatically disconnected from the group regulation system.

(c) Manual control of the central voltage controller should be provided.

Group regulation devices are available in several variants.

Schemes for equalizing reactive loads. One of such schemes developed in the Soviet Union is shown in Fig. 2-5. The scheme includes d.c. motors *1* acting

upon the AEC devices of the generators through actuator units *AU*. The number of motors and actuator units is the same as the number of generators sharing the reactive loads. The field circuits of the motors are connected to an external d.c. source. The armature coil of each motor is supplied with current proportional to the reactive component of the stator current.

Used in the reactive load equalizing device in place of the reactive component of the stator current is the rotor current proportional to this current or

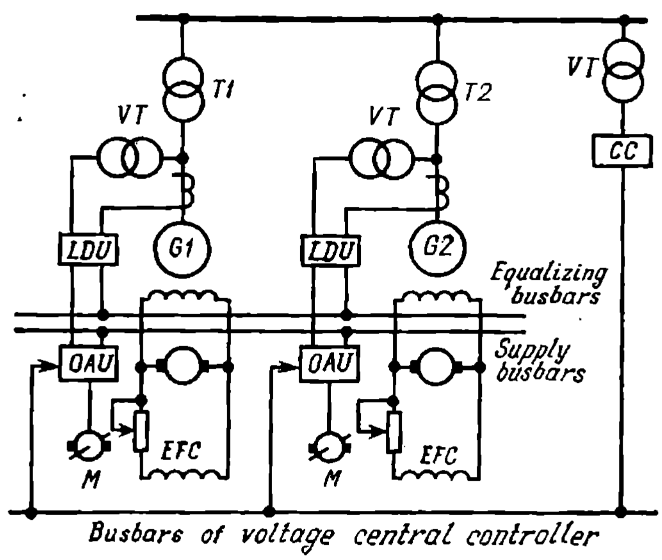


Fig. 2-6. Group excitation control with equalizing reactive loads and central voltage controller

CC — central voltage controller; *LDU* — load distribution unit; *OAU* — output amplifiers unit; *EFC* — exciter main field coil; *M* — regulating rheostat motor

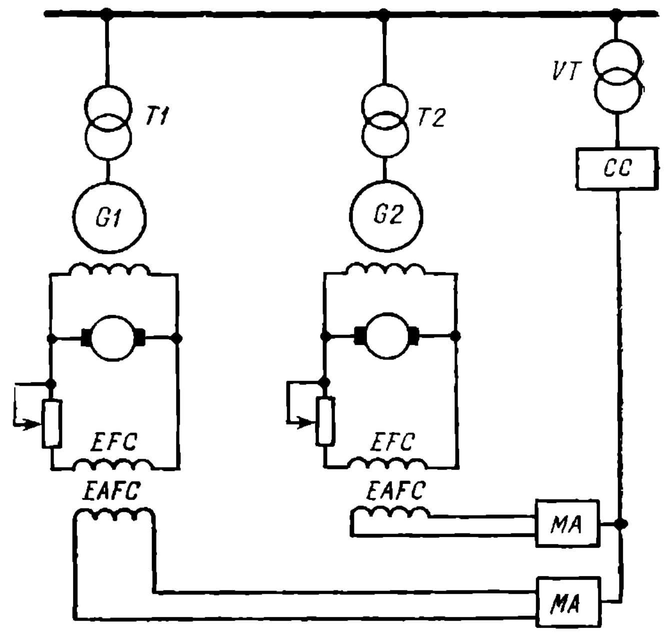


Fig. 2-7. Group excitation control with a central voltage controller

CC — central voltage controller (corrector); *M* — power amplifier; *EAFC* — exciter auxiliary field coil; *EFC* — exciter field coil

the voltage taken from the field coil (U_{rot}). To prevent objectionable electrical couplings between the field circuits of different machines, the voltage U_{rot} may be supplied from constant-current transformers carrying the rotor voltage or current.

When the reactive load balance between the generators is disturbed, a current appears in the motor armatures proportional to the voltage which is equal to the algebraic difference between the mean voltage of the rotors and the rotor voltage of each generator. Depending on the direction of this current, the motors start revolving in this or that direction and act on the AEC devices through the actuator units until the generator rotor voltages become equal to one another.

Figure 2-6 is another scheme for group control of generator excitation [2-2]. The function of the load distribution unit *LDU* is to measure and compare the reactive loads of the generators. The unit is fed from the current transformers connected into the stator circuits and from the potential transformers connected to the generator terminals. The load distributor output current is amplified

by the output amplifier unit *OAU* and acts upon the change in the excitation of the generators. The excitation (field) is controlled by means of the motors operating the regulating rheostats of the exciters or by operating the adjustment devices of the individual electromagnetic voltage correctors. Such a system of

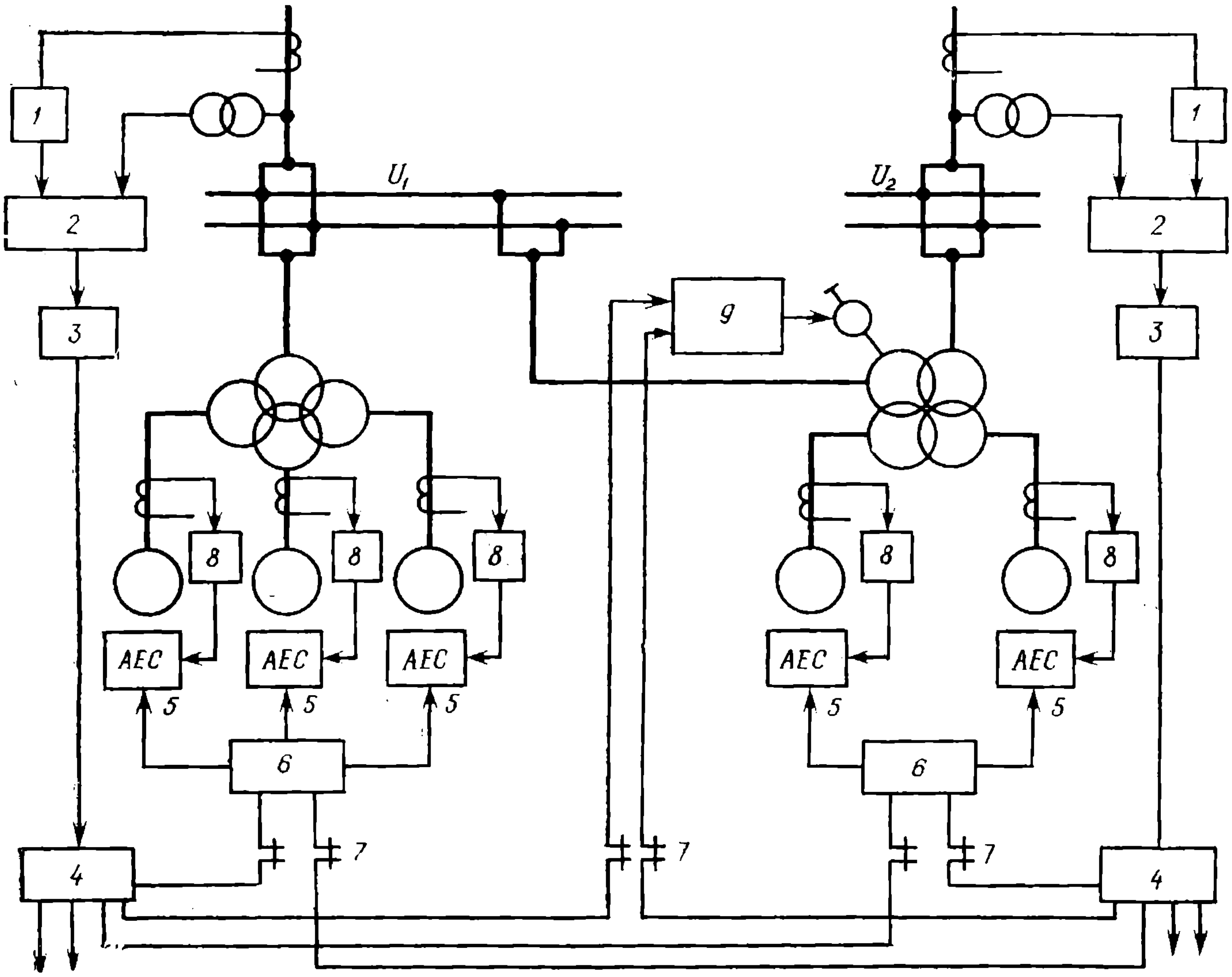


Fig. 2-8. Group excitation control circuit with a central voltage controller and a device for distribution of reactive loads

control (regulation) equalizes the reactive loads in an aperiodic manner, 30 to 60 s after the reactive power distribution between the machines has been disturbed to ± 30 per cent of the power rating of the generators.

Group regulation scheme with a central controller. Reactive load balance between paralleled generators is obtained by using generators with similar external characteristics. The scheme means replacing the individual voltage correctors with a common one (Fig. 2-7)[2-3]. The output current of the central controller (*CC*) corrector is increased by the magnetic amplifiers *MA* and feeds into the exciter auxiliary field coil *EAFC*. The scheme is simple and contains no movable parts,

but calls for similar adjustment of the external characteristics of the generators, otherwise, the difference between the reactive loads of the generators may be significant causing underloaded and overloaded machines.

Group control scheme with a central controller and a device for distributing reactive loads against prescribed schedule. For the block diagram of the device see Fig. 2-8. This device was developed by A. Moskalev and others of the All-Union Power Engineering and Electrification Scientific Research Institute.

The voltage value required at a given point of the power system is set by voltage controller *1*. The value of the set voltage can be corrected either automatically according to the power flow in the transmission line or by the operator with the aid of remote control. Measuring element *2* compares the busbar voltage to the specified voltage. If these voltages differ then, depending upon the sign and magnitude of the difference, a pulse is fed via amplifier unit *3* to load distributor *4*. The latter acts upon AEC devices *5* of the individual generators so that the reactive power requirement may be fulfilled by any machine.

If an electric power station has several sections that can operate in parallel, then all the generators of the station under such operating conditions are drawn into the voltage regulation operation. To this end the AEC device of each generator is acted on through device *6* which adds the output signals of load distributors *4* installed for the separate generator groups. The electrical connections between load distributor *4* and summing devices *6* are controlled by contacts *7* which close when the corresponding section is paralleled.

To prevent long-time reactive current overloads on the generators, use is made of limiters *8* which allow continuous operation of the AEC device within certain limits. If maintenance of the voltage at the specified value requires a change in the transformation ratio of the power transformers, this operation is carried out by device *4* (through control unit *9*) which changes the transformation ratio of the power transformers under load. This operation may be performed at once, if the busbar voltage has changed to a value at which it is expedient to vary the transformation ratio of the power transformers, or after the regulating capacity of the generators has been exhausted.

An essential advantage of the AEC device is that all the generators of the power station can be used for voltage regulating purposes with the possibility of distributing the reactive loads among them in compliance with the desired characteristic even when the generators operate in parallel in sections of different voltages. The design of the device is, however, very complicated, this is the main disadvantage.

2-4. Automatic Devices for Changing the Transformation Ratio of Power Transformers

Automatic changes in the transformation ratio of power transformers are undertaken so that consumer voltage may be maintained at a certain level. The transformation ratio regulation by tap changing is accomplished in a step-like manner. Continuous control of the transformation ratio through changes

in the magnetic state of the magnetic circuit by magnetizing it is sometimes used for low rated transformers intended to handle special loads.

When designing the sensing element of the regulator step-like changes in the transformation ratio of ordinary power transformers under load must be taken into account. The regulator must have a dead zone which overlaps the voltage overregulation value after the regulating device is switched through one step.

Regulation must be slow in order to prevent the switching device from operating during short-time voltage variations as frequent operation may damage the mechanism. The output control signal is usually executed within 20 to 30 s. The sensing element of the regulator can respond to a change in the voltage at the regulator location, to a change in the value of the vector voltage sum at the regulator position with a voltage drop because of a current flow in an equivalent resistor, i.e., to a change in the voltage at a certain point in the power system electrically close either to the load-centre substation or to the connection point of the current receivers, and to a change in the value of the voltage at the regulator position with a correction by the value of the current flow in the feeding line or by the value of reactive power.

To control the transformation ratio, when under load, the transformer tap-changer position is sometimes changed also automatically by a programmer installed at the substation or at the operator's point, to follow an hour schedule, for instance.

When a transformer with automatic control of the transformation ratio is installed at the receiving consumer substation, it is better to accomplish the voltage regulation together with the correction of the current flowing in the feed line or the value of reactive power. If such correction is not used, then, tending to maintain a constant voltage across the consumer terminals in case of a drop in the voltage due to increased losses when the load grows, the regulator switches over the regulating device of the power transformer in order to reduce the transformation ratio. The result will be an increase in the current flowing through the feed line and additional losses with further reduction of the voltage across the terminals of the power transformer.

Along with the principle of regulating the voltage by following its deviation from the maximum permissible value, there is another principle, namely, that of regulating the voltage by following the integral of the squared voltage deviation from the set value taken for a given period of time. The latter principle is based on the fact that the damage to the national economy caused by voltage variation is roughly proportional to the variation of the voltage square per time period under consideration. This relationship holds only for certain types of load and cannot be taken as valid for all the cases encountered in practice.

Whether the regulating criterion has been chosen properly can be substantiated by statistical calculations using data taken over a long period. Whatever the regulating principle, the control system must maintain the voltage within the limits permitted by the load of the power system region.

Let the voltage regulator principle be studied on the basis of the TsSRZAI type (ЦСРЗАИ) regulator known for its simple construction (Fig. 2-9).

The control relays *1CR* and *2CR* control the tap changer of the power transformer by means of auxiliary relays *3AR* and *4AR* and time relay *5TR*. The relay coils are fed with a.c. power. Relays *1CR* and *2CR* are two-coil polarized

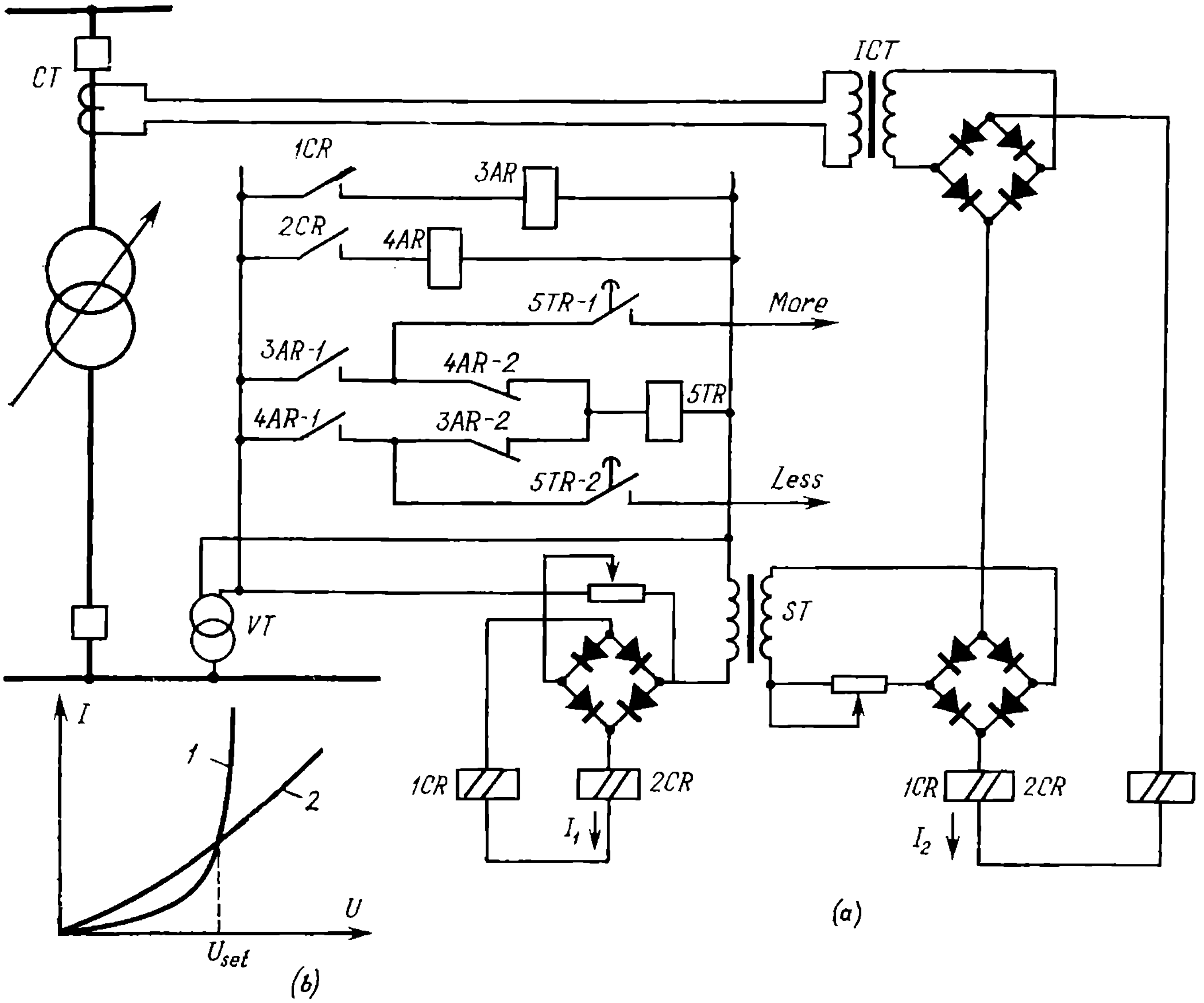


Fig. 2-9. Voltage regulator, type ЦСРЗАИ
(*a*) schematic diagram; (*b*) currents in coils of relays *1CR* and *2CR*

relays (the coils are in opposition). Under normal conditions the resultant emf of the relay armature is equal to zero and its contacts are opened. One of the coils of relays *1CR* and also of *2CR* are connected through rectifiers to the terminals of the instrument voltage transformer *VT* in series with the winding of a quickly saturable transformer *ST*. Depending upon the value of terminal voltage *U* of the instrument transformer *VT*, the current L_1 flowing in one of the coils of relays *1CR* and of *2CR* has a clearly nonlinear characteristic (curve *1* in Fig. 2-9*b*).

The other coils of relays *1CR* and *2CR* are connected to the secondary circuits of the voltage transformer *ST* and the intervening transformer *ICT*

(Fig. 2-9*a*). The primary of the transformer *1CT* is connected to the secondary winding circuit of the current transformer *CT*. The behaviour of the current I_2 flowing in the other coils of relays *1CR* and *2CR* conforms to curve *2* in Fig. 2-9*b*.

The settings are adjusted by means of a series resistor and tap changing on the intervening transformers so that at the voltage equal to the set voltage, the currents I_1 and I_2 equal each other. Departure of the voltage from the specified value causes relays *1CR* and *2CR* to function.

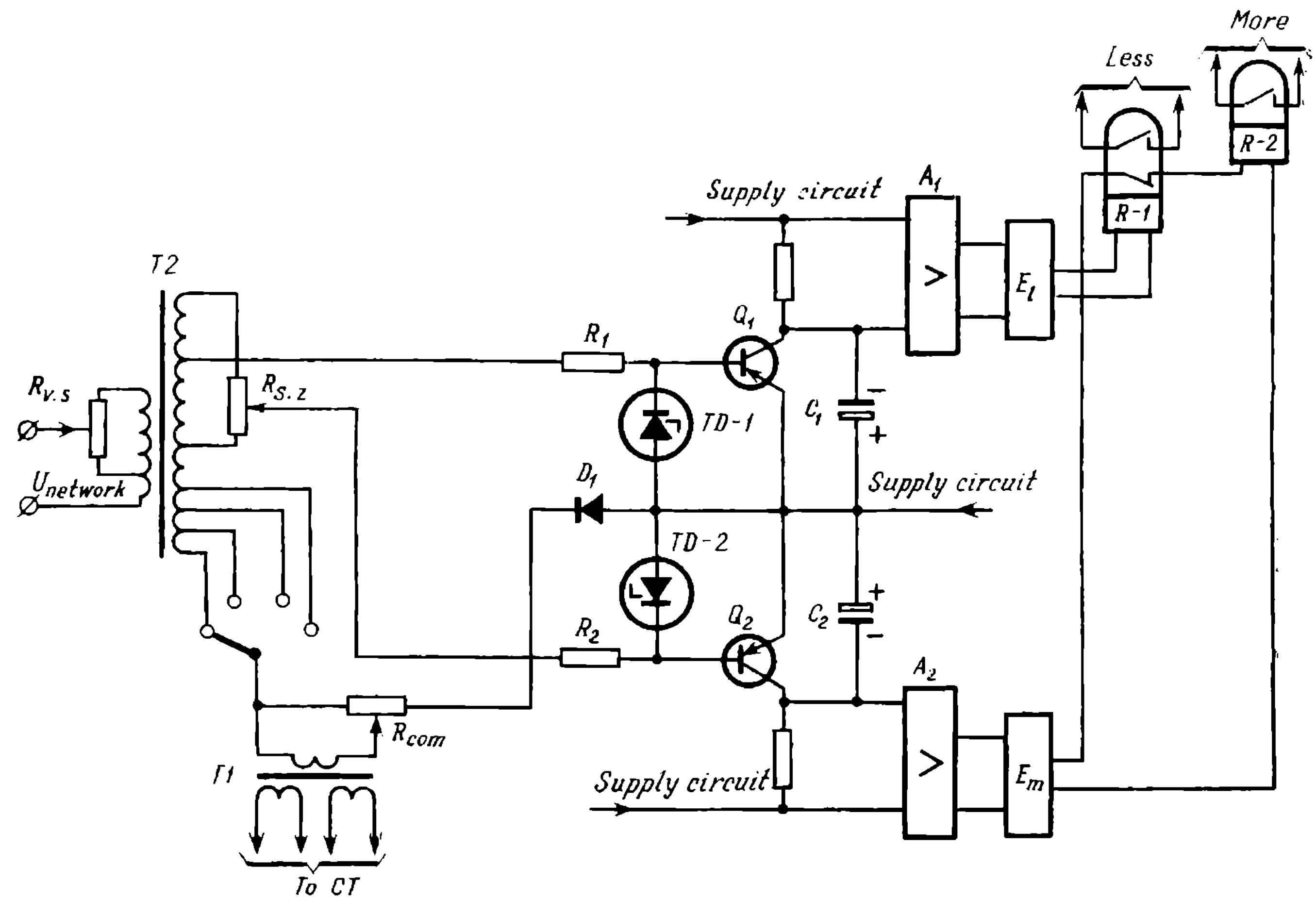


Fig. 2-10. Voltage regulator circuit using tunnel diodes

On the suggestion of engineer Ya. Barkan, the Riga factory "Latvenergo" manufactures power transformer automatic transformation ratio control units, [type BAURPN-2 (БАУРПН-2)] for transformers furnished with on-load transformation ratio control. The device is transistorized. The measuring element utilizes tunnel diodes. For the block diagram illustrating the operating principle, see Fig. 2-10. A specific feature of the tunnel diode is that it has a low resistance only at a certain value and polarity of the applied voltage (Fig. 2-11). This gives the diode a valve property, i.e., use is made of a tunneling effect which arises after the applied bias has reached the magnitude and polarity at which the diode becomes conductive.

The voltage regulator includes a measuring element, a current compensation device, time delay elements and an actuator.

The setting is adjusted by varying the resistance of resistor $R_{v.s}$ connected on the primary side of the intervening transformer *T2*. The minimum value of the voltage setting is 90 volts and the maximum 110 volts. The setting can be

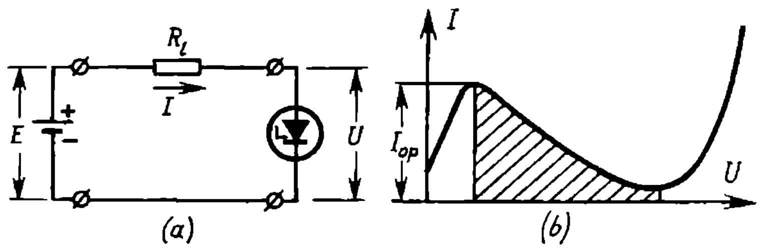


Fig. 2-11. Principle of operation of tunnel diode
(*a*) triggering circuit; (*b*) tunnel diode characteristic, $I = f(U)$

adjusted continuously in the range of 95 to 105 volts. The inert zone is adjustable within 1 to 6 per cent of the setting voltage with the aid of the resistor $R_{s.z}$. Taken from this resistor by means of its slide is the voltage fed via resistor *R2* to the transistor *Q2* of the MORE channel. The transistor *Q1* of the LESS channel is connected to the tapping of the secondary winding of transformer *T2*.

Fig. 2-12. Oscillogram of tunnel diode pulses

In every other period of alternating current, when the current amplitude exceeds the operating current I_{op} of the tunneling diode, the latter is flipped (the shaded zone in Fig. 2-11*b*). The resistance of the tunnel diode abruptly rises which accounts for the pulse operation of the circuit under control (Fig. 2-12).

When acted upon by the pulses, the transistors *Q1* and *Q2* (Fig. 2-10) start shaping interrupted pulses to control the LESS and MORE channels through amplifiers *A1* and *A2*. In order to maintain the control signals (pulses), when the tunnel diode is quickly reset, as the sinusoid of the voltage taken from the transformer T2 passes the zero point (the resetting ratio of the tunnel diode $k_r = 0.2$), use is made of capacitors *C1* and *C2*. The discharge time of the capacitors is overlapped by the on-off time of the pulses shaped by the tunnel diodes *TD-1* and *TD-2*.

The interrupted operation of tunnel diodes provides a resetting ratio of 1 for the whole device, since the repeated functioning of the tunnel diode is possible only when the amplitude of the current in the circuit again exceeds the operating current (voltage).

Transformer *T1* and resistor R_c, compensate for the voltage drop in the power transmission line between the substation where the regulator is installed and

the consumer where the specified voltage is to be maintained. When the current flows only in the primary winding of transformer *T1*, the internal shift angle of the current flowing in the secondary winding amounts to 26-30 deg, this determines the connection of the primary winding of the transformer *T1* to the current transformer of the lagging phase.

The time delay element made of semiconductor elements can provide continuous adjustment for 1 to 2 min. Fig. 2-10 shows two time delay elements

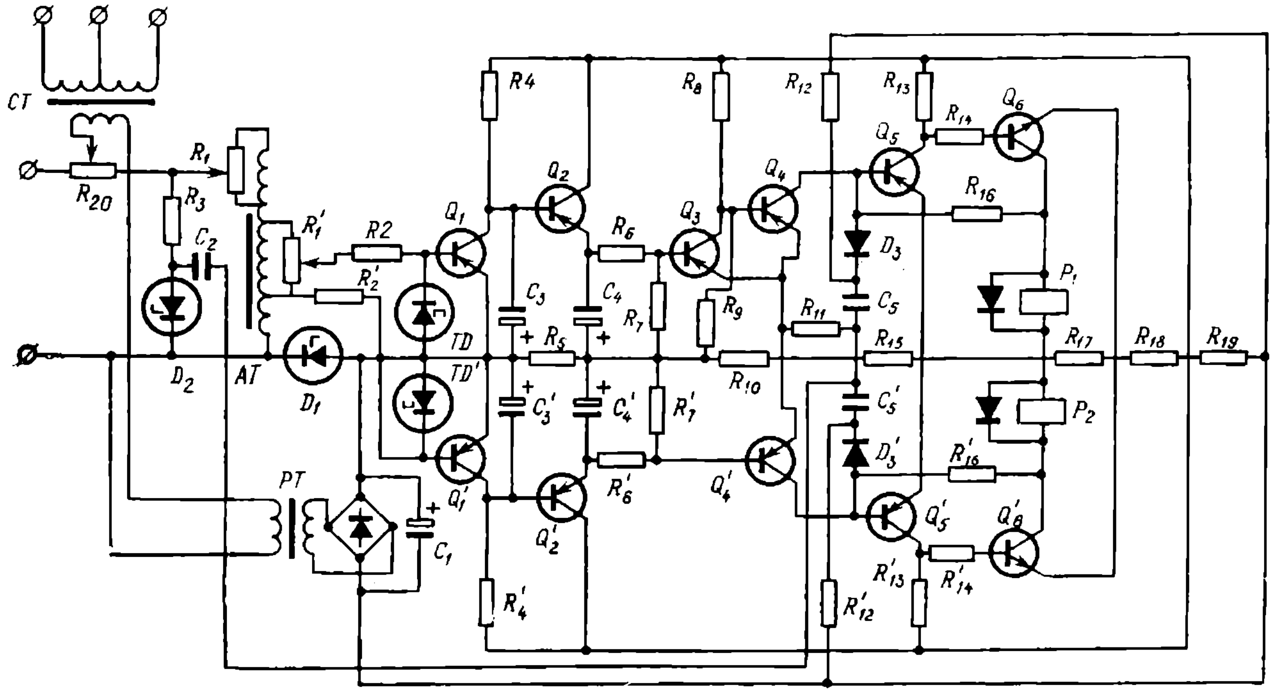


Fig. 2-13. Voltage regulator circuit with two time delay elements based on tunnel diodes

E_l and E_m which ensure independent operating times for the LESS and MORE channels. The output signal of these channels is realized with the aid of relays *R-1* and *R-2*.

Operation of the relay *R-1* makes the tap changer of the controlled transformer increase the input voltage of the voltage regulator above its dead zone, while the operation of the relay *R-2* causes it to decrease this voltage below the dead zone.

The regulator may utilize only one common time delay element. However, if this is the case, there will be no possibility of separately regulating the operation time of the LESS and MORE channels. When the relay *R-1* functions, the circuit of the relay *R-2* opens to prevent their simultaneous functioning in case the inert zones of the channels overlap each other.

For a complete schematic diagram of the pulse voltage regulator employing tunnel diodes see Fig. 2-13. According to the description compiled by the designer, Ya. Barkan[2-2], the operation of the regulator is as follows[2-4].

The lower channel makes the voltage decrease. In the starting (initial) position the transistor *Q'1* is cut off, while the transistors *Q'2* and *Q'4* are

conducting. The transistor *Q'4* bypasses the capacitor *C'5* of the time delay element and feeds the cutoff potential to the base of the transistor *Q'5*. The result is that the flip-flop is in the starting position. The transistor *Q'6* is cutoff and the relay *R2* is deenergized. The upper channel does not function in the initial position either. In this channel the similar state is provided when pulses are fed to the tunnel diode. The first transistor periodically becomes conductive. The pulses are "rectified" by the capacitor *C3*. The transistor *Q2* becomes cut off. After the capacitor *C4* has discharged, the transistor *Q4* also stops conducting. The cutoff pulse is removed from the flip-flop and capacitor *C5* charges. After it is charged to the potential applied to the emitter of transistor *Q5*, the diode *D3* is ready to start conducting. The next pulse in sequence from the on-off wave generator (avalanche diode *D2* and capacitor *C2*) is fed through the diode and flips the flip-flop. The time delay flip-flop utilizes transistors of distinct types which are in similar states. When flipped, both of the transistors are triggered into conduction and the relay functions.

The same happens to the other channel when the pulses disappear from the tunnel diodes. The discharge resistor *R11* may be small in rating. In this case the voltage return to the dead zone cancels the time delay. Repeated operation of the regulator involves almost full time delay. When the discharge resistance is commensurate with the charging resistance *R12*,the time delay is not canceled at once when the voltage returns to the dead zone. Repeated operation of the measuring element will make the regulator operate with a smaller time delay. In this case the time delay accumulates.

The divider is fed from the transformer PT through a rectifier bridge. The capacitor *C1* serves as a filter. The power consumption is 0.5 VA for the measuring element and 2 VA for the divider.

2-5. Devices for Automatic Capacity Control of Capacitor Banks

When capacitor banks are used at the substation and at the loads, automatic voltage regulation is attainable by switching on or off the capacity of the capacitor banks, depending upon the voltage across the terminals of the sensing element or upon the value and polarity of the reactive power passed over the feed line, or upon the current flowing in this line. Often the capacity of the bank is switched on or off due to a combined effect of all or some of the above-mentioned factors. The control of the capacitor banks may be also from a programmer device, the simplest case being, for example, an electrical contact-type clock.

Available from the Riga factory, "Latvenergo" are transistorized devices, type ARKOH (APKOH)[2-5], which are used to control capacitor banks. The regulator provides for voltage regulation with a correction as to the current and the phase angle between the current and voltage. The regulator incorporates a controller and 10 actuator units.

Let us consider the operating principle of the device controlling capacitor banks from the relaying circuit shown schematically in Fig. 2-14.

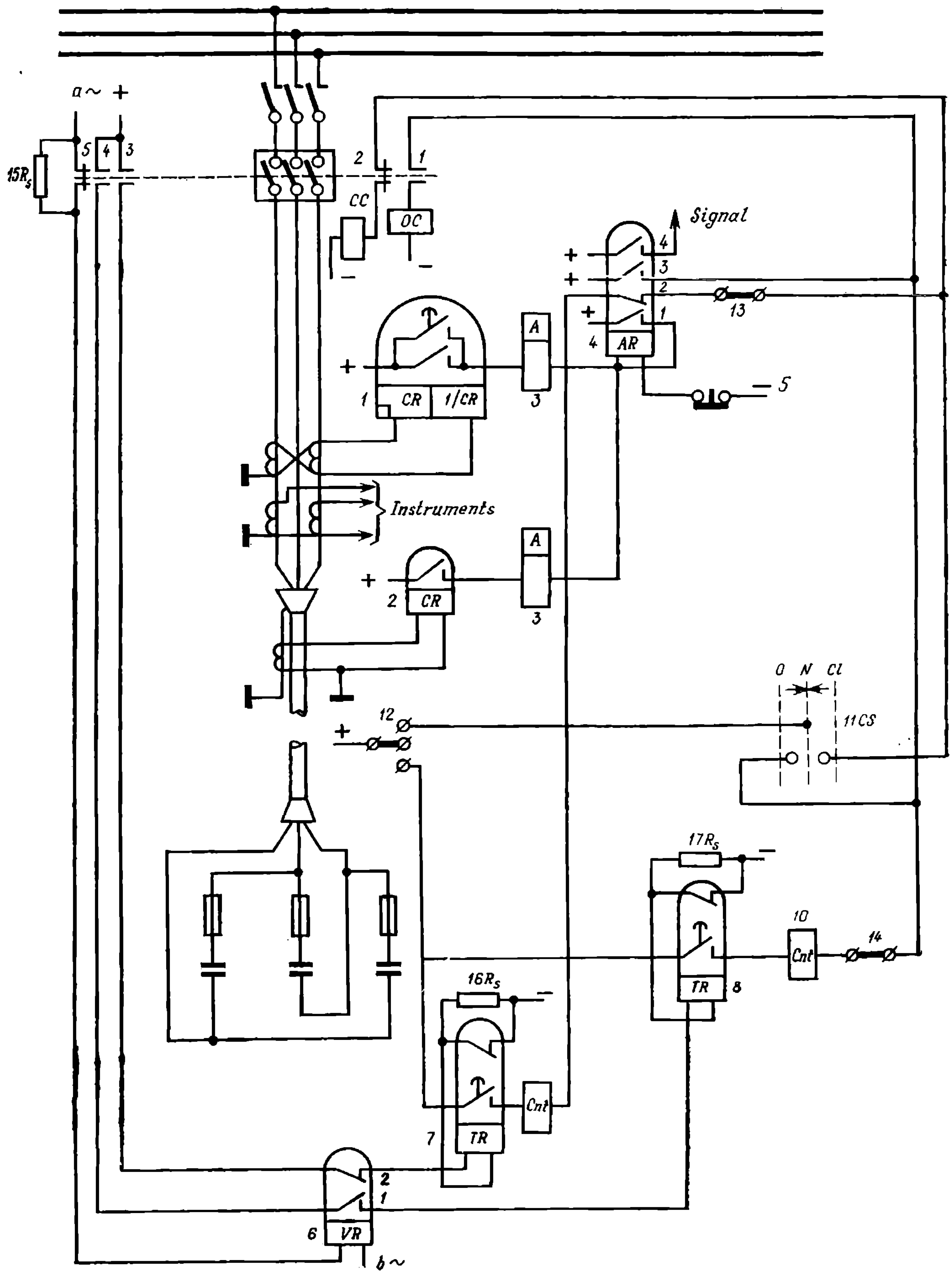


Fig. 2-14. Capacitor bank control circuit diagram

The power supply to the control circuits and the automatic control devices is from a potential transformer connected to the substation busbars. The device can operate either on the operating current or on a rectified current from a supply unit. Fig. 2-14 illustrates the variant with the use of rectified current. Used as the sensing element is a voltage relay with one front contact and one back contact. With the switch opened, the resistor $15R_s$ is short-circuited by the auxiliary contact of the switch and relay *6VR* receives the interphase voltage U_{ab}. If this voltage is less than the reset voltage of relay *6VR* ($U_{relay} < U_r$) the *6VR-2* contact is closed. The time relay 7TR is closed and after the specified time period it sends a signal to turn on the capacitor bank. The signal is fed through the making (front) contact *4AR-2*.

After the bank has been turned on, the busbar voltage of the substation, as a rule grows. To prevent the bank from immediate disconnection, the operating setting of relay *6VR* is automatically changed by connecting series resistance $15R_s$ in series with its coil. In this case relay *6VR* operates only when the voltage grows in excess of the increased operating setting. The capacitor bank is disconnected after the operating time of relay *8TR* has elapsed.

The operating time of relays *7TR* and *8TR* lies within 20 to 30 s to prevent superflous switching operations in case of short-time voltage variations.

The resistors $16R_s$ and $17R_s$ ensure the thermal stability of the coils of relays *7TR* and *8TR*. These resistors are connected instantaneously by the time relay contact after the solenoid plungers of the actuators of these relays have retracted. In the picked up state the current flow in the relay is less than the pick-up current and somewhat above the reset current. The number of on-off switchings is recorded by counters *9* and *10*. Switch *12* is used to change over to the manual or automatic control mode. The manual control is effected through the control switch (*11CS*).

The protective relaying of the capacitor bank guards it against interphase faults and overloads by means of current relays *1* which are inverse time lag devices with a definite minimum. A current cutoff provided in the relay functions in case of a phase-to-phase fault. In addition, the circuits of capacitor banks ranging from 6 to 10 kV are furnished with a fuse. Relay *2* protects the banks against earth faults.

Signal relays *3* monitor the operation of the protective relaying system. When the protective relaying system functions, relay *4* opens the turning-on circuit of the switch to prevent automatic switching-on of the bank at fault by the contact of relay *7TR*. The relay (*4AR*) is of the self-retaining type. The circuit is reestablished by operating push-button *5* which opens the self-retaining circuit. The functioning state of relay *4AR* is monitored. To disconnect the automatic control circuits, use is made of jumpers *13* and *14*.

When placing capacitor banks into service, provision should be made for their forced operation, i.e., for a heavy rise in the network capacitance when the voltage drops below 85 per cent the rating. This is because the effect of the static compensators decreases with a decrease in the voltage. As

$$I_C = \frac{U}{x_C} \tag{2-13}$$

the current I_C decreases proportionally when the voltage U drops with invariant x_C, which causes additional reactive losses and a further drop in the voltage, i.e., the process attains an avalanche character. This voltage drop can be stopped by an abrupt drop of the x_C value, i.e., by an abrupt increase in the current I_C and reduction of the reactive losses.

An increase in the capacitance current is attainable by switching on additional capacitor banks or by switching over the capacitors, as per scheme shown in Fig. 2-15, from the interphase voltage, when the phase current is

$$I_C = \frac{3U_{ph}}{2x_C} = 1.5\,\frac{U_{ph}}{x_C} \tag{2-14}$$

to the phase voltage, when the phase current becomes equal to

$$I_C = \frac{U_{ph}}{0.5x_C} = 2\,\frac{U_{ph}}{x_C} \tag{2-15}$$

This switching operation is effected through switch *2*.

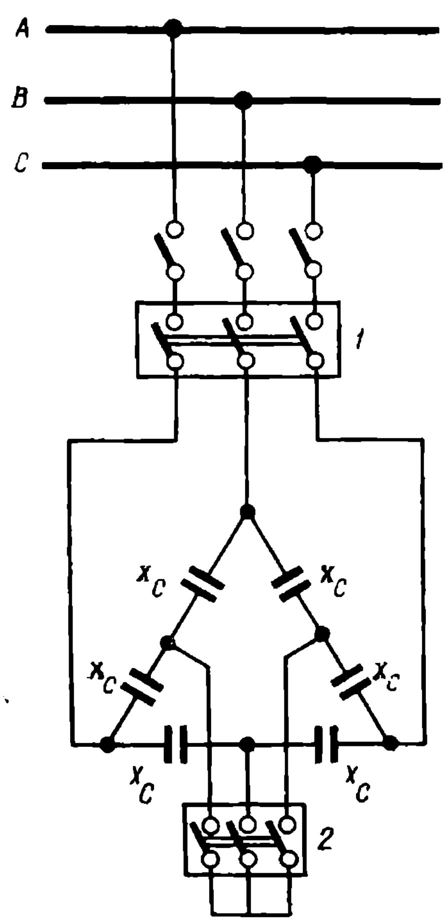


Fig. 2-15. Forcing of capacitor bank

2-6. Voltage Regulation by Booster Transformers

Diagrams showing the regulating process are given in Fig. 2-16. The secondary winding of the booster may be connected directly into the transmission line or in series with the windings of the power transformer (near the terminals on the neutral point side of the power transformer). The primary of the booster transformer is fed from 3 to 10-kV busbars through an auxiliary variable-ratio transformer. Regulation is either vector-coincident or composite, depending on whether the vector of the specified voltage coincides with or is shifted relative to that of the voltage being controlled (Fig. 2-16*c*). In the latter case, not only is the voltage changed in its value, but it undergoes a phase shift too. This makes the so-called phase-shift regulation obtainable, which can be used to eliminate excessive power losses arising due to some nonuniformity of parallel transmission lines. The transformation ratio control mechanism of the auxiliary transformer is adjusted either manually or automatically.

2-7. Voltage Regulation by Changing Excitation of Synchronous Capacitor

The busbar voltage of the receiving substation can be regulated within certain limits by varying the excitation mode of the synchronous capacitor installed at the receiving substation and by providing operating conditions with leading or lagging current.

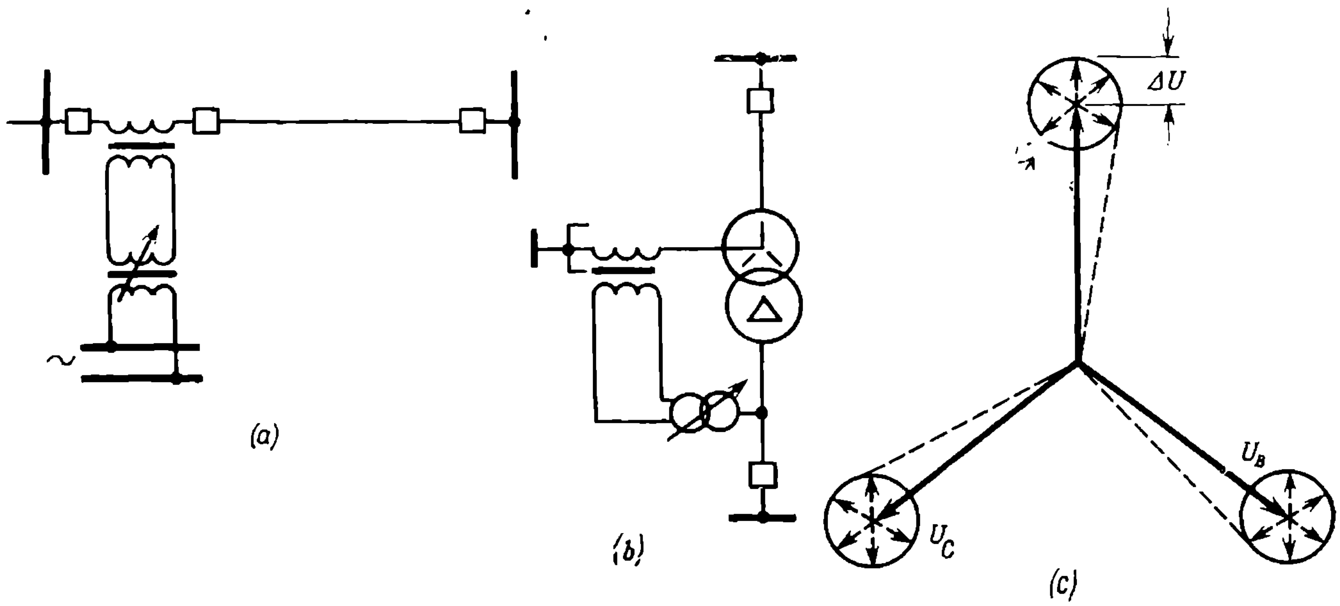


Fig. 2-16. Connection of booster transformer

(*a*) in series with power transmission line; (*b*) same with power transformer winding; (*c*) voltage regulation principle

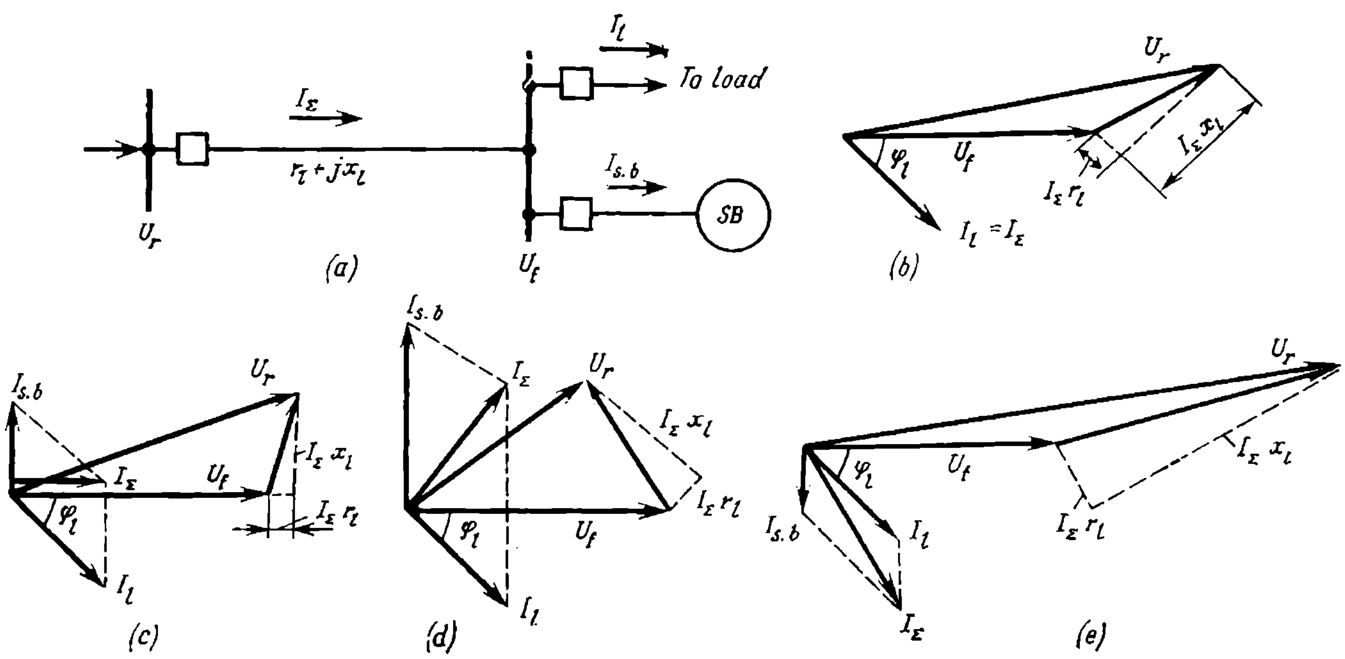


Fig. 2-17. Voltage regulation by changing current in synchronous capacitor and power factor

(*a*) supply circuit; (*b-e*) vector diagrams

Let U_r be the busbar voltage of the receiving substation (Fig. 2-17*a*). The load current I_l is lagging this voltage by angle φ_l. When no capacitor is used, the feeding end voltage is determined from the diagram given in Fig. 2-17*b*. It is clear that if the busbar voltage of the feeding substation U_f is constant, the busbar voltage of the receiving substation will change with the change of the load current. When the use is made of a synchronous capacitor, the inductive component of the load current can be compensated for with resultant operation at $\cos \varphi = 1.0$ (Fig. 2-17*c*). Overcompensation with a leading current flowing in the feeding line may be obtained as well (Fig. 2-17*d*).

In the case when voltage in the power system and across the busbars of the feeding substation rises significantly, the load voltage can be reduced by changing the capacitor to an underexcitation mode of operation (Fig. 2-17*e*).

Thus by changing the field current of the synchronous capacitor and using either the leading current or lagging current mode of operation, the magnitude and phase of the feeding line voltage losses can be changed in order to control the voltage of the receiving substation within the required limits.

2-8. Voltage Regulation by Controlled Reactors

A new possibility of regulating the voltage in high-tension networks is offered by the use of controlled reactors, the inductive reactance of which is changed by varying the steel core magnetizing current.

Magnetization is performed by a rectified alternating current. If this current is formed by a potential transformer connected to the busbars of the power receiver, then a short-circuit makes the busbar voltage drop to zero, the reactance of the reactor automatically and abruptly rises and, if the reactor is coupled to the short-circuit current, then the short-circuit current value decreases, i.e., the reactor performs the function of a current limiter (switch).

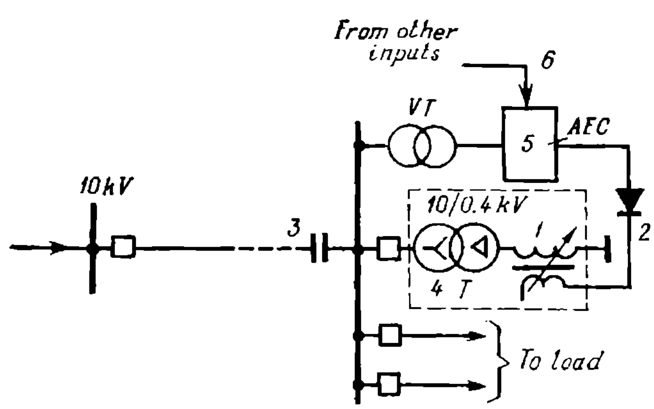


Fig. 2-18. Automatic voltage regulator using a controlled reactor

1 — controlled reactor (choke with superposed magnetization); *2* — rectifier device; *3* — bank capacitance; *4* — transformer; *5* — automatic voltage regulator; *6* — auxiliary inputs to regulator

The controlled reactor can be used to change the value of the capacitance current in the line due to a capacitor bank employed by the consumer or because of capacity susceptance of the transmission line (the latter is essential for long lines of 500 kV and more) not only discretely, but continuously, in compliance with the assigned mode of regulation. The controlled reactor may be used to perform phase-shift regulation by the quantities of the power flows in the transmission lines. An advantage of the use of a controlled reactor is the absence of switching devices to perform switching operations in the circuits

being controlled (except for the switches needed to deenergize the reactor when it is at fault or for other reasons). How a controlled reactor is used for voltage regulation purposes can be seen from a study of Fig. 2-18.

The controlled reactor is installed at the receiving substation either in parallel or in series with the capacitor bank. Regulation of the value of the capacitance current flowing in the transmission line and thus changing the voltage across the load is obtainable by varying the inductive reactance of the reactor through changes in the magnetizing current. This method, when necessary, makes it possible to abruptly increase the capacitance current with only a very small delay, which produces an effect similar to forcing the capacitor banks. The prescribed mode of regulation is fulfilled by an automatic voltage regulator.

Data exists on the successful operation of a voltage regulation system at the consumers end of a 10-kV network in Byelorussia where a controlled shunt reactor and a capacitor bank were installed at a substation with only occasional attendance over a period of several years[2-6]. Abroad, controlled reactors are used for vector-coincident and phase-shift voltage regulation in a number of 66 to 220 kV power networks.

2-9. Conclusions

1. Maintenance of the voltage rated level at power system nodes and at consumer points is an important indication of the generated power's quality.

2. Automatic excitation regulation devices allow the voltage regulation process to be automated to some degree. This is also helped by the devices used for automatic control of the transformation factor of power transformers and for changing the capacitor of static capacitor banks.

3. The use of controlled reactors for automatic voltage regulation purposes is promising.

4. Systems for group excitation regulation of generators ease the work of personnel who control the operation of power units, making it possible to operate the generators of a multiunit power station as one composite generating unit.

5. When static capacitors are installed at the consumers in the form of lumped capacitance banks to prevent an avalanche voltage drop, the capacitance current must be automatically and sharply raised by decreasing the capacity reactance x_C of the capacitor bank after the initial drop in the voltage, whatever the cause may be. When a controlled reactor is used in parallel with the capacitance, its reactance must be sharply increased in order to raise the capacitance current in the line. Where synchronous capacitors are available, provision should be made for excitation forcing and automatic excitation regulation devices similar to those used with synchronous generators.

2-10. Review Questions

1. What is the difference between the astatic and static characteristics of voltage regulation?
2. What is current stabilization and current compensation in voltage regulation devices? Explain the purpose of each and field of application.
3. How are the specified reactive loads distributed between paralleled generators working into the generator voltage busbars?
4. How are the specified reactive loads distributed among generator-power transformer sets working into common busbars? Why is it necessary to observe a definite distribution of reactive loads among the generators and astatic voltage regulators under such operating conditions?
5. Explain voltage regulation in power systems. Why is it insufficient to use AEC device solely for voltage regulation of synchronous machines?
6. Describe group excitation regulation of generators at a multiunit power station. What is its purpose and possible application?
7. Explain the purpose and possibility of use of automatic voltage regulators controlling the transformation ratio of power transformers.
8. Why is it possible to change the voltage level at a node of a power system by connecting lumped capacitance banks? Under what conditions should the banks of capacitors be disconnected?
9. What is the purpose of automatic forced operation of capacitive compensation devices (capacitor banks at the receiving end) and excitation of synchronous capacitors?
10. Describe programmed voltage regulation, its purpose and field of application.
11. Explain automatic regulation of voltage across the receiving substation busbars with utilization of a controlled reactor and capacitor bank. What is the advantage of this method as compared to automatic regulation by switching over capacitor banks in order to change the capacitance current value?

Chapter Three

EXCITATION SYSTEMS AND AUTOMATIC FIELD DISCHARGE DEVICES OF SYNCHRONOUS MACHINES

3-1. General

The excitation systems and the field discharge devices of synchronous generators and motors are considered in detail in textbooks on synchronous machine operation. This chapter presents some principles describing the development of the above-mentioned systems which assure correct operation of automatic power system control assemblies and protective relaying devices.

There are *separate* excitation systems in which the supply of exciting current to the field winding of a synchronous machine is from an independent

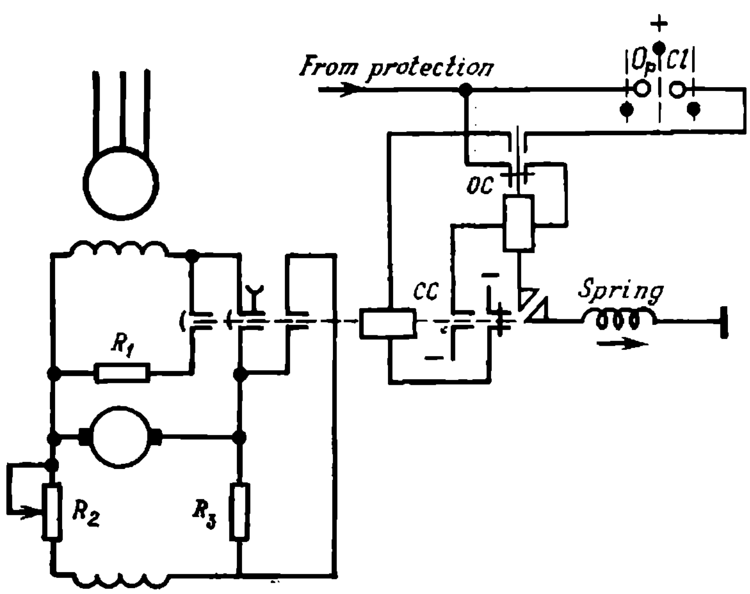


Fig. 3-1. FDC with rotor winding changed over to discharge resistor R_1 and resistor R_2 connected into exciter field circuit

d.c. source, the emf of which is independent of the operation of the given synchronous machine (an example is the current supplied from an individual motor-generator set or from a rectifier unit fed from an individual a.c. source) and *self-excitation* systems in which the supply of current to the field circuit of a synchronous machine is from a d.c. source, the emf of which is dependent upon the generator speed, voltage or current.

Figure 3-1 illustrates a widely used variant of exciter circuit employed in conjunction with a field discharge control (FDC) and AEC[3-9]. When the

circuit is of the self-excitation type the continuous current generator is mounted directly on the shaft of the synchronous generator rotor. If the continuous current generator (exciter) is driven by an individual motor supplied from the power system, use is made of separate excitation.

To improve the reliability of excitation systems, the tendency is now to replace d.c. commutator machines by semiconductor devices.

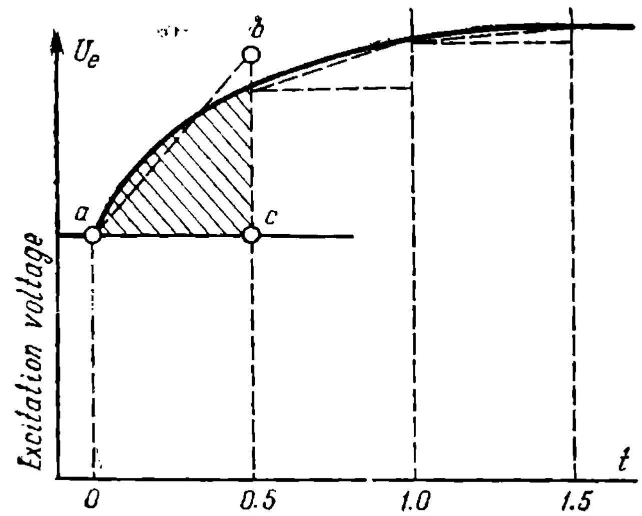


Fig. 3-2. Determining the mean rate of excitation rise

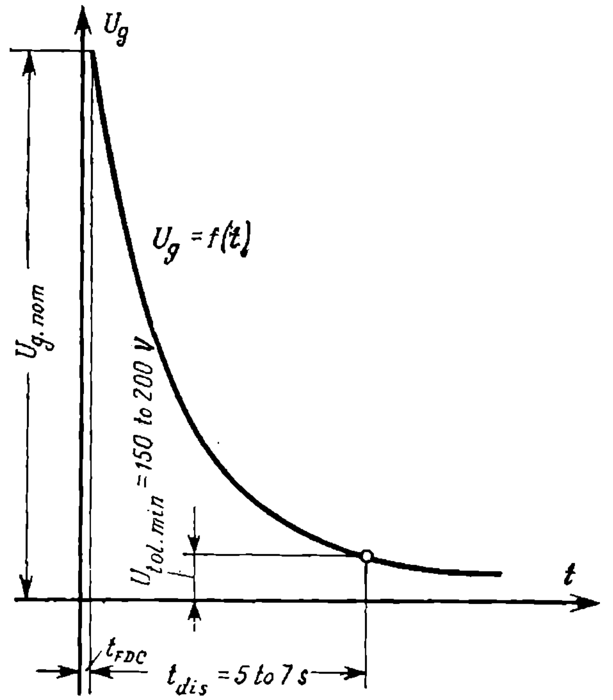


Fig. 3-3. Changes in generator voltage after operation of FDC according to Fig. 3-1 (no-load running); t_{FDC} is FDC operating time

The performance of forced excitation devices and AEC devices employed with automatic control facilities which are intended to raise the stability of generators working in parallel is materially improved by using rapid rate excitation systems with high excitation ceilings.

The *mean rate* of excitation across the synchronous machine rotor terminals is determined by the tangent of the angle at which the *ab* side of triangle *abc* (Fig. 3-2) is inclined with respect to its abscissa, the area of the triangle being equal to the shaded area limited by the actual curve of the voltage rise per 0.5 s.

The *ceiling excitation voltage* is determined by the excitation current factor with respect to the magnitude of the *excitation current* at normal operation of the generator and rated current of the exciter. The multiplicity factor of rotor current with respect to the rated current allowed for a definite time is specified by the manufacturer for each type of exciter. If the forced excitation duration exceeds the permissible time, the automatic control devices must reduce the excitation current (must perform deexcitation) and if the result is other than a droop in the rotor current to the specified value, they should disconnect the

generator and discharge its field. These circumstances have been considered in Chapters 1 and 2.

In compliance with the State Standard GOST, the excitation systems must ensure an excitation forcing multiplicity factor of not less than 2 for generators and synchronous capacitors, while the rate of excitation rise should be not less than 2 units of excitation/second.

The field discharge control (FDC) disconnects the excitation circuit of the rotor winding from the d.c. source or another method is used to stop the current flow in the rotor circuit, such as the cutting out of semiconductor devices. The action of the FDC is more effective when the stator emf quickly drops to the value at which arc self-extinguishing occurs in case of damage to the stator insulation. Self-extinguishing of arc usually occurs at 500 volts or less. The residual emf due to the residual magnetization does not exceed 150-200 volts.

The functioning of the FDC is compulsory when faults occur inside the generator. The generator operation is allowed without excitation during self-synchronization until the generator reaches the hypo-synchronous speed and the rotor winding is changed over from the discharging resistance to carry the full field current. Disconnection of the FDC during normal operation of the generator results in asynchronous operation with respect to the power system.

If reserve power is available in a power system, the generators which lose their excitation are automatically disconnected as the blocking contacts of the FDC device send a trip signal to the output relay of the protection system. With a shortage of active power in the power system, the turbogenerator may be allowed to operate without excitation for some time (15 to 30 minutes), provided the active load of the generator in asynchronous operation is reduced to a value approximately 40 per cent of the rating so that the generator is protected against current overloading.

With the TGV-200 (ТГВ-200) and TGV-300 (ТГВ-300) turbogenerators employing gas-discharge tube excitation and the TVV (ТВВ)-165-2, TVV-200-2 and TVV-320-2 generators which use excitation energy from semiconductor rectifiers, operation of the FDC devices and arc extinction may cause overvoltages dangerous to the insulation materials of the rotor. Written directives[3-1] prescribe the use of discharges operating at 2.4 kV (1.7 kV_{act}) to protect the rotor insulation against ruptures.

To prevent dangerous overload of rotors having forced winding cooling, their excitation control devices are furnished with a forcing limiter.

In FDC devices which switch the rotor windings to a discharge resistor (Fig. 3-1), the stored electromagnetic energy is dissipated in the form of heat by resistor *R1*. The greater this resistance, the higher the voltage across the rotor terminals and the quicker the field discharge process. The permissible voltage across the rotor terminals depends on the insulation effectiveness. Usually the resistance is four- to five-fold of the rotor winding when in the warmed state. Resistance *R2* is about 10-fold the resistance of the exciter field coil again in the warmed condition.

When the generator is idling the field discharge time is 5 to 7 s. The rotor current and the value of emf drop follows the exponential curve (Fig. 3-3). The

differential equation describing the rotor current change has the form

$$L \frac{di}{dt} + (R_1 + r)\, i = 0 \tag{3-1}$$

hence

$$i = I_0 e^{-\frac{t\,(R_1+r)}{L}} \tag{3-2}$$

where i = current in the rotor winding
L, r = inductance and resistance of the rotor winding
R_1 = resistance which the FDC device connects to the rotor winding terminals
$I_0 = U_0/r$ = initial value of the current in the rotor winding (U_0 is the voltage across the exciter terminals before operation of the FDC device)

In the field discharge control, due to a deion grid which consumes the power accumulated by the rotor winding, the discharge time ranges from 0.34 to 1.4 s. This is far less than the time ensured by the FDC's where the accumulated electromagnetic energy is dissipated in a resistor.

With the gas-discharge tube or thyristor excitation, the field is effectively and rapidly discharged (suppressed) by inverting the exciter and forcing simultaneously the excitation to the upper critical value dictated by the rotor winding insulation. The field discharge time approaches here the theoretical value.

3-2. Exciters Using Gas-Discharge Tubes and Thyristors

Gas-discharge tube exciters supplied from an auxiliary generator[3-2]. Used as the auxiliary generator (Fig. 3-4) is three-phase generator *1* connected to the shaft of the main generator. The field coil of this generator is supplied with rectified current from exciter *2* which is a permanent-magnet elevated-frequency three-phase generator. The field of the main generator is supplied through gas-discharge tube rectifiers from auxiliary transformer *3* having delta-double-wye connection. To prevent arcback damage, use is made of anode reverse-current circuit breakers *A* with a device for automatic single-short reclosure. The rectified current circuit is controlled by biasing the control grids of the mercury-arc rectifiers and with the aid of the contacts of cathode circuit breakers *K* which protect the rotor circuit against shorts.

Another variant of the gas-discharge tube exciter supplied from an auxiliary generator connected to the shaft of the main generator is shown in Fig. 3-5. The group of low-voltage rectifiers is supplied from part of the turns of the auxiliary generator and is intended for excitation control under normal operating conditions. The full voltage of the auxiliary generator is applied to the high-voltage group of rectifiers which are used for excitation forcing.

The gas-discharge tube excitation is controlled by an automatic excitation control (AEC). The power supply to the gas-discharge tube control cabinet is from the house circuits whose power is backed-up by a transformer connected to the terminals of the auxiliary generator. The rectifiers are protected against

arcback damage by reverse-current circuit breakers with one-shot automatic reclosure. The auxiliary generator has an AEC device with compounding and an electromagnetic voltage corrector.

Gas-discharge tube exciter with a series-connected transformer[3-3]. One circuit diagram variant for this exciter is shown in Fig. 3-6. The mercury-arc rectifiers

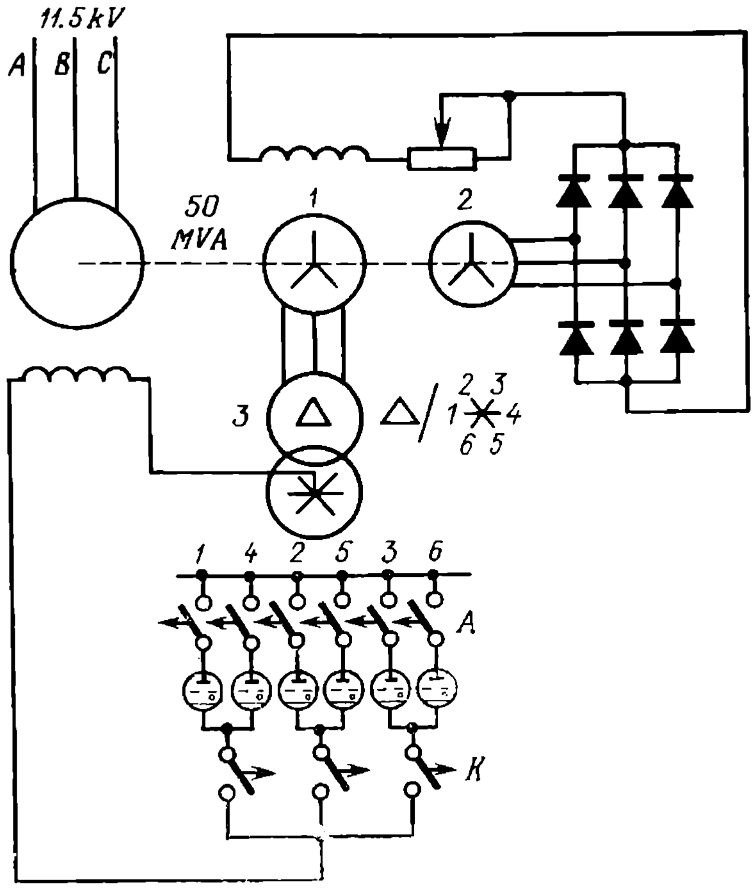


Fig. 3-4. Gas-discharge excitation circuit fed from auxiliary generator

are supplied from anode transformer *6* which is connected via the winding of a series transformer to the stator voltage of the generator. The excitation is controlled by AEC *5* connected to instrument transformer *3*. The automatic excitation control acts upon the mercury-arc rectifiers via control cabinet *4* which is supplied from house circuit transformer *2*. When short-circuit faults occur and cause the voltage across the stator terminals to drop the power supply to the rectifiers is continued from transformer *1* due to current in the winding series connected with the generator stator winding. The rectifiers are protected against reverse currents by circuit breakers *7*.

An advantage of this exciter is in that it uses no rotating parts. The gas-discharge tube exciters utilizing the above-mentioned circuit are most promising.

Quick-response exciters employing thyristors. The circuits for excitation of synchronous machines with the use of thyristors are similar to the excitation cir-

cuits utilizing controlled gas-discharge devices. By way of illustration Fig. 3-7 shows a block diagram of the thyristor exciter developed at the Kharkov turbogenerator plant for synchronous motors[3-4, 3-5].

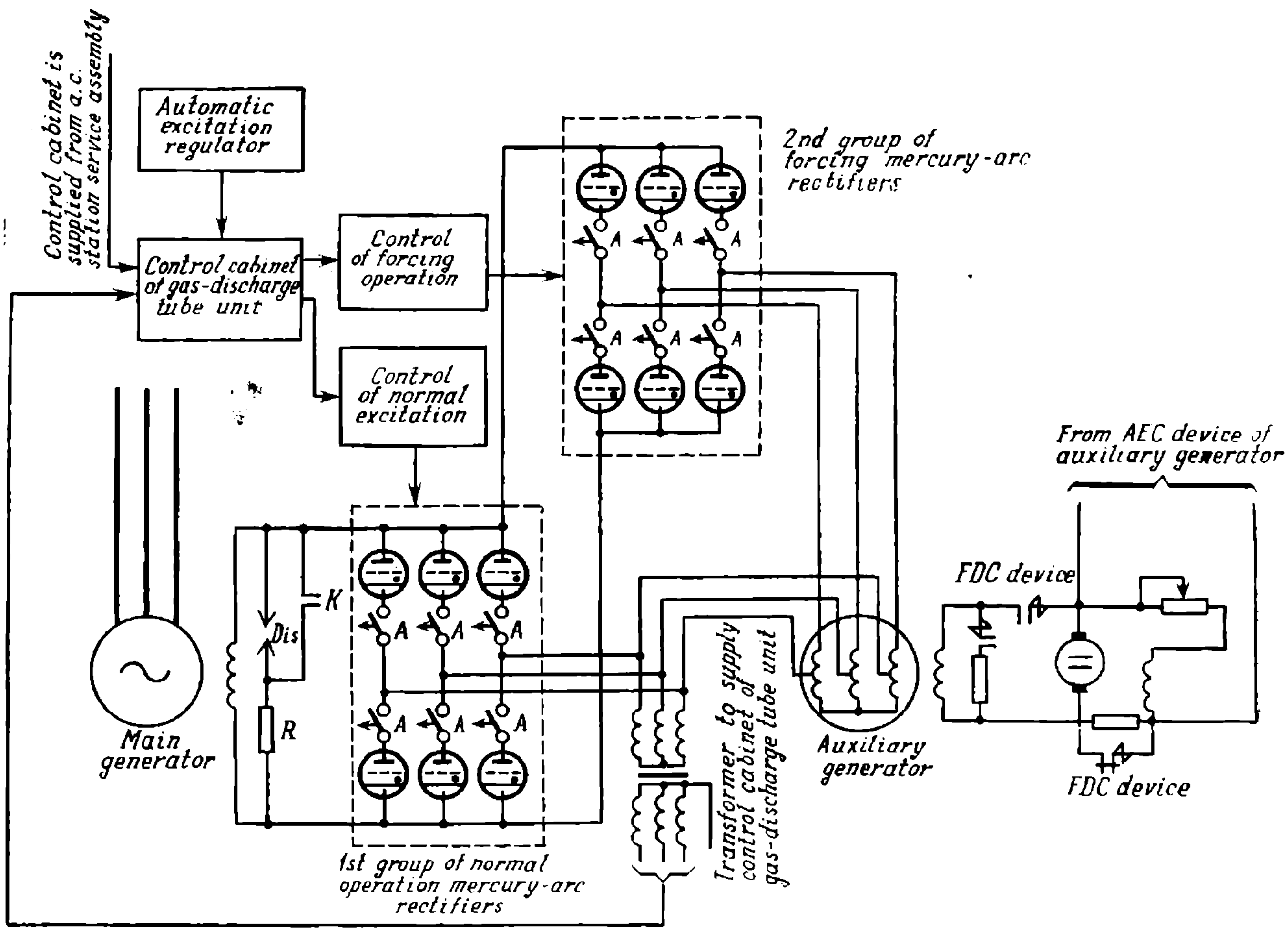


Fig. 3-5. Gas-discharge excitation device energized from auxiliary generator mounted on the main generator shaft

A — contacts of anode reverse-current circuit breakers with one-shot reclosure; *Dis* and *R* — discharger and current limiting resistor to protect against overvoltages which may occur when arc is interrupted in valves or when anode circuit breakers come into action; *K* — contactor contact cutting in resistor *R* for starting by self-synchronization method

The thyristor is controlled by control device *CD* which sends shaped pulses to activate the thyristor making it conductive or nonconductive and to determine the magnitude of current flowing in the rotor winding. This current (in value and polarity) depends on the instant the control signal α is produced by the control angle unit *CAU*. The thyristor is supplied from a step-down transformer through filtering device *F* which eliminates upper current harmonics. Current measurements are taken with the aid of shunt *Sh* from the short-circuit protection unit *SPU* which, in case of a short-circuit in the supply circuit of the thyristor, acts upon the control unit to cut off the thyristor, discharge the field and disconnect the motor through the output protective relay.

When the motor is started the thyristor is nonconductive. The rotor winding is short-circuited to starting resistor R_s via thyristor switches *Th1* and *Th2*.

Due to the effect of the induction torque, the motor speeds up to a hyposynchronous speed. The current measurements in the R_s circuit are taken from the starting resistor protection unit *SRP* which measures the voltage drop across the voltage transmitter *VT*, the voltage being taken from the terminals of a saturable inductor. The *SRP* unit acts on the control pulse shaping unit *PSU*. When the hyposynchronous speed has been reached, the *SRP* unit cuts off thyristors *Th1* and *Th2* and with the aid of the *PSU* triggers the thyristor unit into conduction, thus feeding the field current from the supply transformer to the rotor winding. If the motor is at fault and its protection is functioning, a signal is sent to the *SRP* unit which makes thyristors *Th1* and *Th2* conduct and simultaneously cut off the thyristor unit. Thus the field is discharged and the motor is switched to the starting duty. Similarly, the *SRP* unit may be used to change the synchronous motor to operation with removed excitation and discharged field for subsequent self-synchronization of the motor after recovery of the stator terminal voltage.

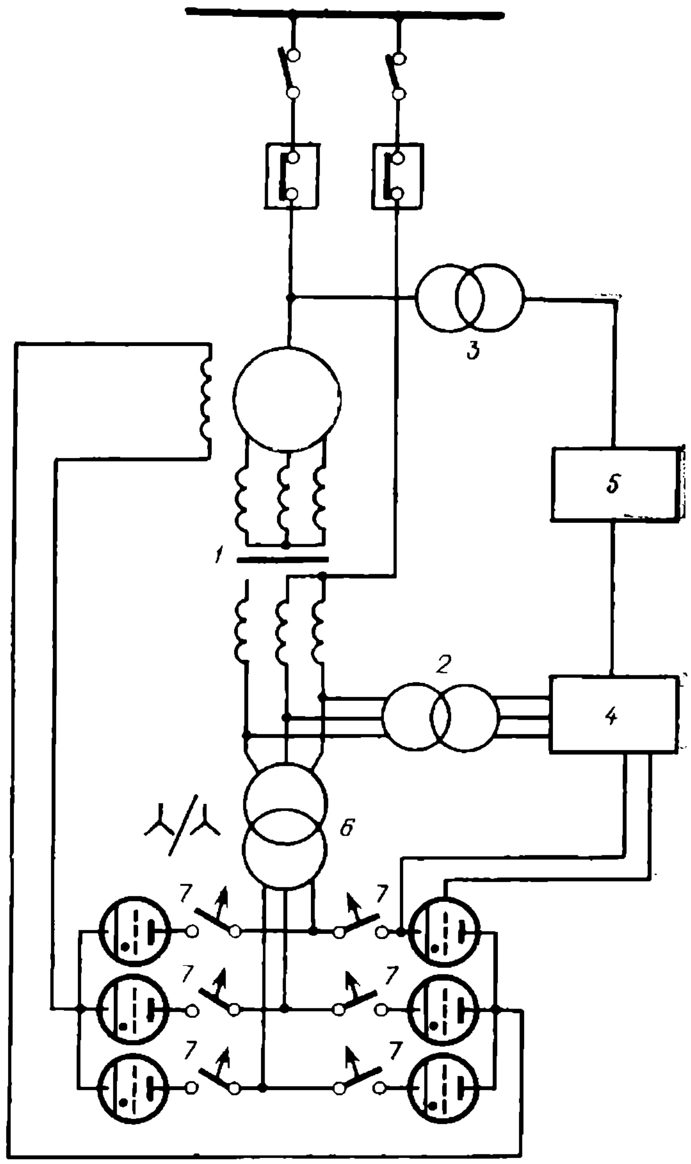


Fig. 3-6. Gas-discharge excitation circuit with series connection of supply transformer into generator stator circuit

The forcing limiter unit *FLU* is connected to the rotor winding circuit via d.c. transformers *DCT*. When the current flow in the rotor winding circuit exceeds the rated value the *FLU* acts upon the control unit *CD* which in turn reduces the current in the field coil circuit of the synchronous motor to the required value by varying the instant the control signal triggering the thyristor unit into conduction arrives.

The automatic excitation control (for example, a compounding device with an electromagnetic voltage corrector and excitation forcing) maintains the voltage in compliance with the setting U_{set} on the voltage controller. Opening the switch discharges the field. The control signal is shaped by the *SG* device which sends the signal to the control device *CD*. Control for correct starting and

sequence of operations is performed by the *SC* unit which responds to the stator current and acts upon the control device *CD*.

The power supply to the thyristor unit is from a step-down double-wye connection transformer through rectifier bridges. To cool the assembly, use is made of a blower controlled by supply unit *SU* with the aid of contactor *K*.

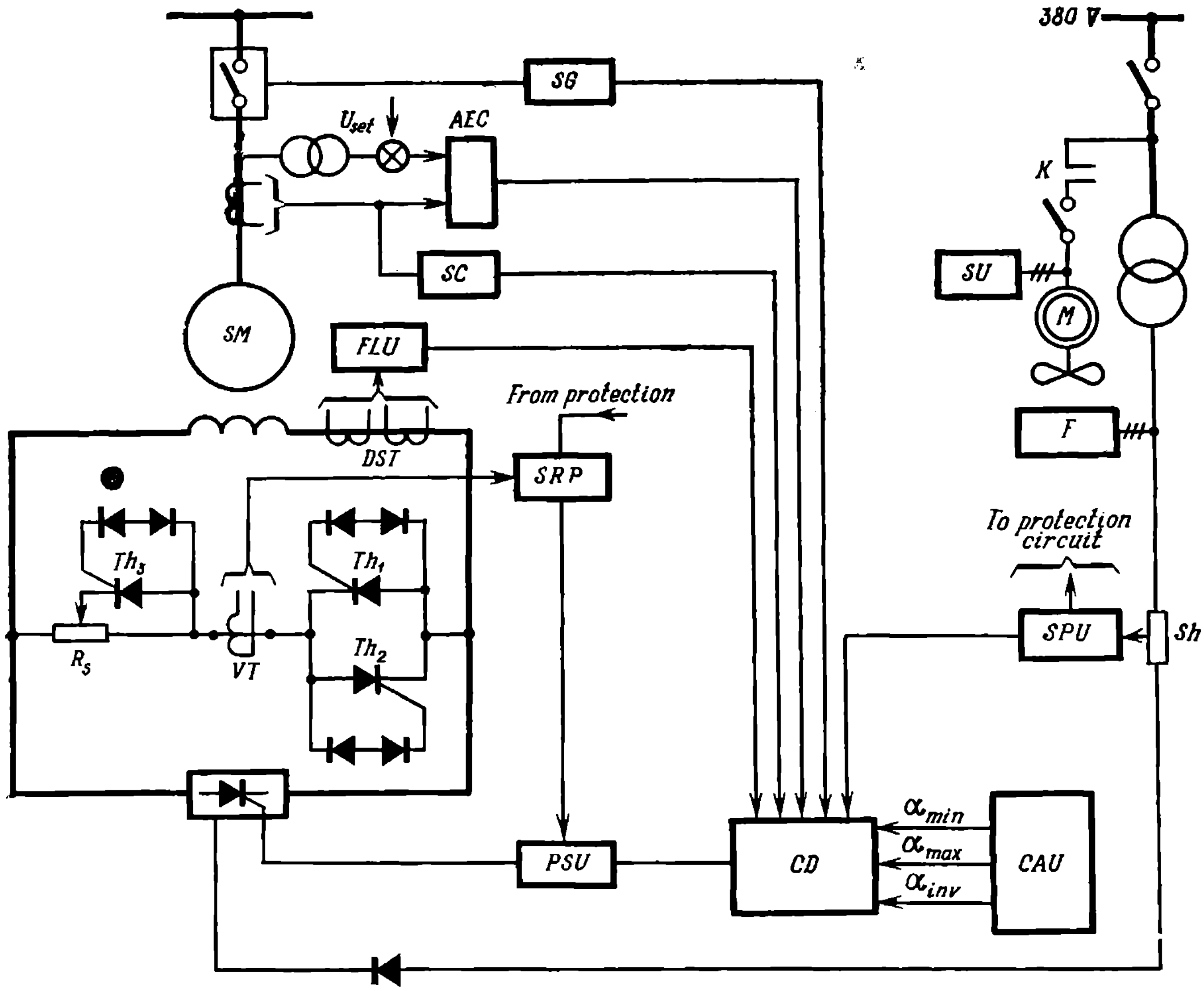


Fig. 3-7. Block diagram of thyristor excitation system

The purpose of the thyristor *Th3* bypassing part of the resistance R_s is to lower dangerous voltages across the starting resistor when an overvoltage occurs during the starting operation.

To discharge the field quickly, provision is made to inverse the current polarity in the field excitation circuit by sending the signal α_{inv} from the control unit through the control device and the control pulse shaper.

3-3. Brushless Excitation System

The design of the brushless excitation system[3-8] is illustrated in Fig. 3-8. Mounted on the shaft of rotor *1* (Fig. 3-8*a*) is the stator of auxiliary generator *2* which revolves together with rectifiers *3* and field coil *4* of the synchronous motor. Stator winding *5* of the synchronous motor is connected to three-phase

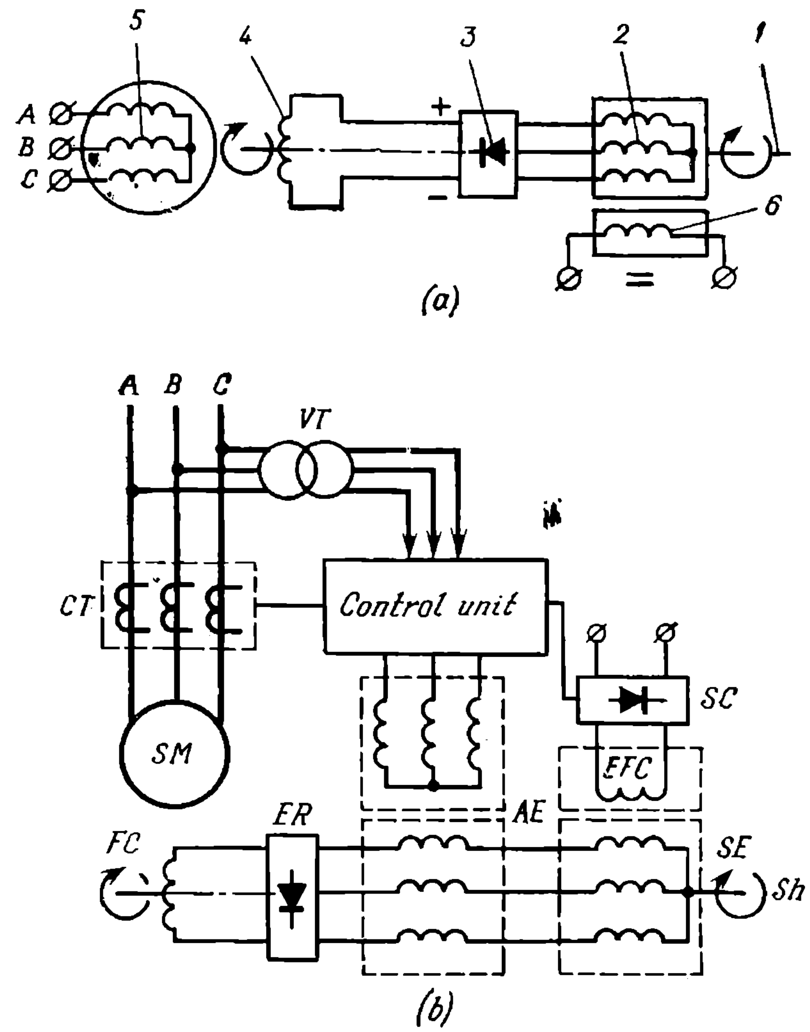


Fig. 3-8. Brushless excitation system

(*a*) synchronous motor; *1* — synchronous motor shaft axis; *2* — stator of auxiliary generator carried by the machine shaft; *3* — rectifier carried by the machine shaft; *4* — synchronous motor exciter (revolves together with shaft); *5* — synchronous motor stator; *6* — field coil of auxiliary generator; (*b*) synchronous machine with cascade asynchronous-synchronous exciter

mains in the usual manner. Field coil *6* of the auxiliary generator is supplied either with direct current or with rectified alternating current. The value of the current in the field coil *4* of the main unit is changed by varying the field current in coil *6* of the auxiliary generator which thus serves as if a subexciter.

Figure 3-8*b* illustrates how synchronous generators can be used with a brushless excitation system. The shaft *Sh* of the synchronous machine *SM* carries a field coil *FC*. The same shaft carries rectifiers *ER*, secondary winding of

asynchronous exciter *AE*, and stator winding of auxiliary synchronous exciter *SE*. The field coil of the auxiliary synchronous exciter (*EFC*) is supplied from static converters *SC* which may be influenced by the control unit.

The main control effect on the field current flow in the rotor winding (*FC*) of synchronous machine *SM* is accomplished by the control unit through the primary winding of asynchronous exciter *AE*.

3-4. Excitation Systems of Large Turbogenerators

For powerful electric machines, use is made either of a dynamoelectric high-frequency excitation system (for the TVV turbogenerators) or a gas-discharge tube excitation system (for the TGV turbogenerators)[3-6]. For the

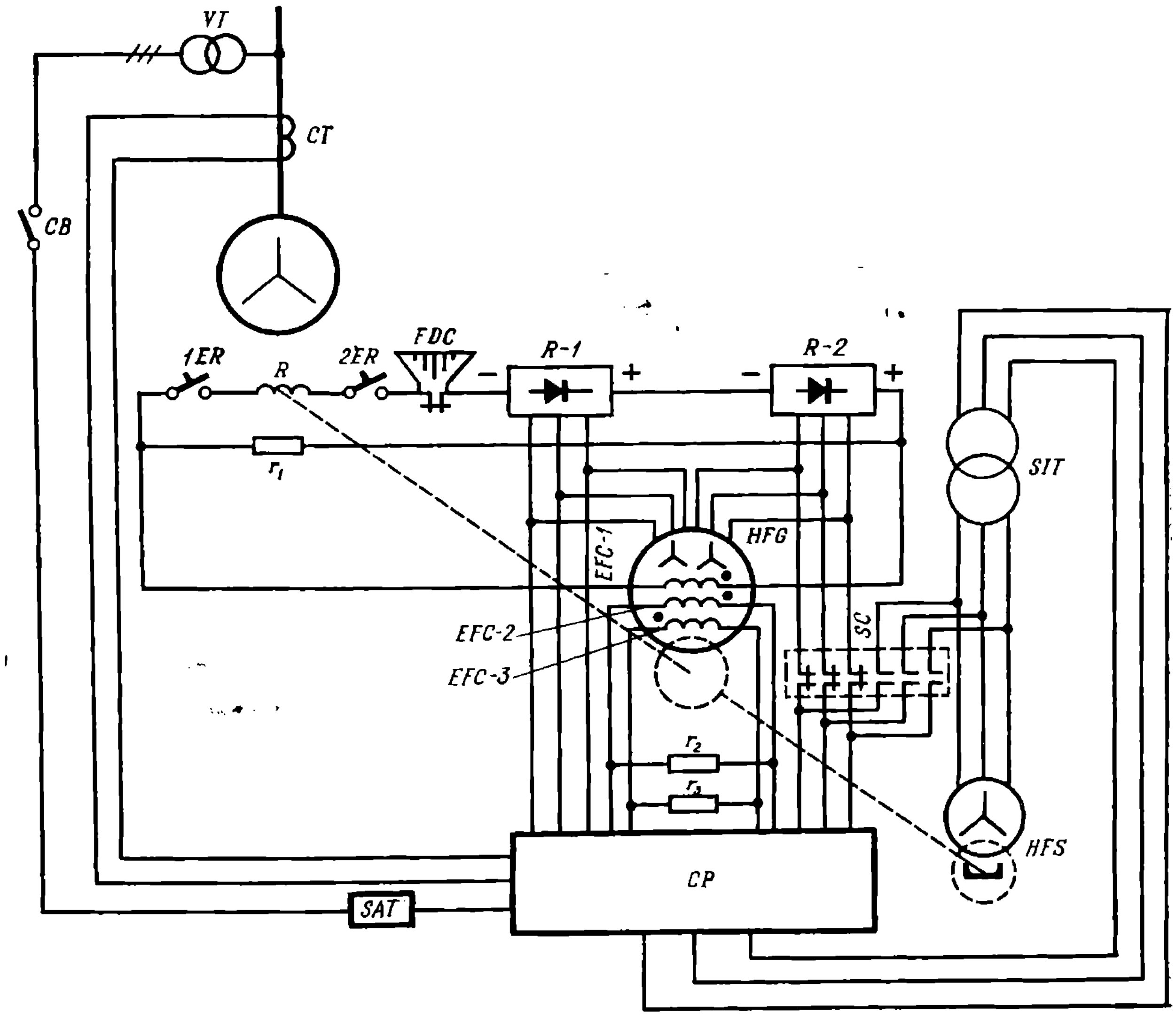


Fig. 3-9. Dynamoelectric excitation with high-frequency a.c. generator and solid-state rectifiers

schematic diagram of a dynamoelectric exciter with a high-frequency a.c. generator and solid-state rectifiers see Fig. 3-9. The rotor of the high-frequency

generator *HFG* is driven by the turbogenerator shaft on which the rotor of main generator *G* and the rotor of high-frequency subexciter *HFS* are assembled.

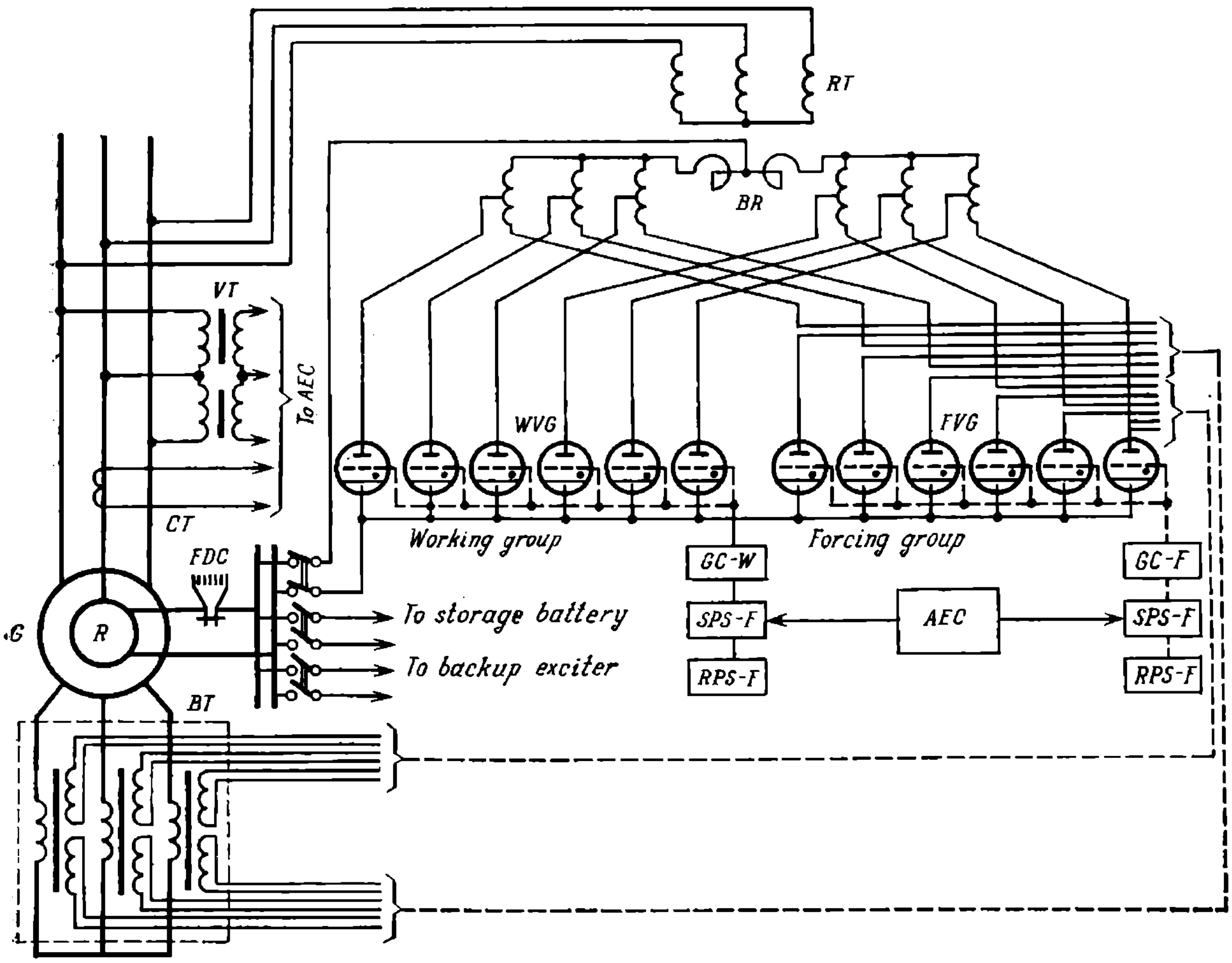


Fig. 3-10. Schematic diagram of gas-discharge tube excitation of turbogenerator TGV-300 (ТГВ-300)

G — generator stator; *R* — generator rotor; *RT* — rectifying transformer; *BR* — balancing reactor; *BT* — booster transformer; *WVG* — working group of valves; *FVG* — forcing group of valves; *GC-W*, *GC-F* are devices for grid control of working and forcing groups of valves; *RPS-W* and *RPS-F*—rotating phase shifters of working and forcing groups of valves; *SPS-W* and *SPS-F* are static phase shifters of working and forcing groups of valves; *FDC* — field discharge control; *AEC*—automatic excitation controller

The rotor of high-frequency generator *HFG* carries no field coils. The coils are located in the slots of its stator. The a.c. windings are fitted in the same slots.

As compared to the system employing d.c. generators the reliability of this excitation system is materially improved due to the absence of a commutator.

The winding *EFC-2* is used for forcing the excitation of generator *G* by means of the quick-response excitation (*QRE*) device. The excitation control equipment is conventionally shown in the form of an automatic control panel *CP* and setting autotransformer *SAT*. The winding *EFC-3* is supplied from the *AER* device on the automatic control panel *CP*. The magnetic amplifiers of

the automatic excitation regulator are connected to the terminals of the high-frequency subexciter *HFS* which is a permanent-magnet machine excited by the permanent magnets of the rotor. The emf excited in the stator windings of the *HFS* generator has a frequency of 400 Hz.

During the start-up of generator *G*, the coils of the magnetic amplifiers of the automatic excitation regulator must be switched over by the contactor *SC* to be energized from the high-frequency subexciter *HFS*. This ensures the subsequent self-excitation of the generator *G* and high-frequency generator *HFG* enabling the contactor *SC* to change the excitation circuit to a position corresponding to normal operating conditions.

The series connection of the *EFC-1* winding with the rotor winding *R* of the generator assures additional excitation current forcing of the main generator *G* due to a free current arising in the rotor circuit in case of a short-circuit at the stator side.

For protection against a voltage rise caused by free current flowing in the *R—EFC-1* windings and inducing currents in the *EFC-2* and *EFC-3* windings, resistors r_1, r_2 and r_3 are connected in parallel with all these windings.

The gas-discharge tube excitation circuit is shown in the diagram of Fig. 3-10. Use is made of composite self-excitation. The rotor current is controlled by phase adjusters operating the grid control device. The rotor receives power from the working and forcing groups of the valves. Under normal operating conditions the main supply (60 to 70 per cent) is from the working group and the additional supply (30 to 40 per cent), from the forcing group of valves. In case of a short-circuit in the generator stator circuit, the forcing group becomes fully conductive with a resultant increase in the rotor current to its permitted value.

3-5. Field Discharge by Deion Grid Automatic Devices and by Changing the Field Coil Supply to Inverter Operation

Conditions for the quickest field discharge. The field discharge occurs most rapidly when during the entire field discharging period, i.e., the time interval when the current in the rotor of the synchronous machine varies from the initial value I_0 to zero[3-7], the stator winding terminal voltage remains constant and equal to the maximum value permitted by the insulation strength.

Let the value of resistance *R1* in the FDC (Fig. 3-1) be far above the value of rotor winding resistance *r*. The differential equation describing the field discharge process in such a device is as follows

$$L\frac{di}{dt}+R_1 i=0 \tag{3-3}$$

According to the above-mentioned facts the field discharge time has its minimum when the energy accumulated in the rotor winding is dissipated at

the maximum rate during the period the FDC device acts. In this case

$$L\frac{di}{dt} = -R_1 i = -U_{\max} \tag{3-4}$$

where $U_{\max}$ is the voltage across the terminals of the rotor winding in the excitation forcing mode.

From equation (3-4) it is clear that the best field discharge conditions in accordance with the diagram in Fig. 3-1 are obtained when the FDC uses resistor *R1* whose resistance varies inversely to the current flowing through it.

Expression (3-4) determines the linear dependence of the current decrease with time

$$i = I_0 - \frac{U_{\max}}{L} t \tag{3-5}$$

In this instance the current falls to zero within the time

$$t_{\min} = I_0 \frac{L}{U_{\max}} \tag{3-6}$$

which is the minimum possible time.

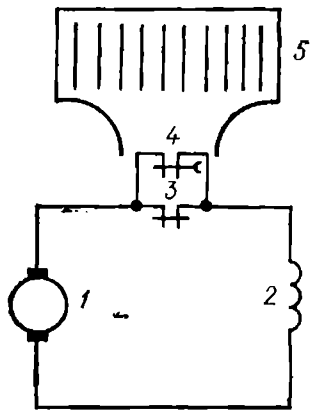


Fig. 3-11. Field discharge control with deion grid

Field discharge with the aid of a deion grid. For the schematic diagram see Fig. 3-11. Through the main contacts of circuit breaker *3* the exciter *1* supplies power to the field coil of generator *2*. When the FDC device functions, main contacts *3* open first and then, somewhat later, deion contacts *4* break. The arc is broken in the crosswise field of magnets and drawn into deion grid *5* that breaks the arc into small portions which stream until the current in field coil *2* drops to zero.

If n is the number of grid plates and U_k is the arc voltage between the plates (25 to 30 volts for copper plates), then the voltage across the whole arc

$$U_a = nU_k \tag{3-7}$$

It has been shown experimentally that this voltage remains constant almost within the entire range of current variations. The differential equation describing the transient process is as follows

$$L\frac{di}{dt} + ri + U_a = U_0 \tag{3-8}$$

where L, and r = inductance and resistance of the excitation winding
U_0 = exciter voltage until the field discharge control starts functioning

The solution of equation (3-8) determines the current variations with time

$$i = \frac{U_0}{r} - \frac{U_a}{r}\left(1 - e^{-tr/L}\right) \tag{3-9}$$

Since the voltage drop across the deion grid significantly exceeds the voltage drop across the rotor winding resistance (3-8) may be simplified without

the risk of a large error

$$L\frac{di}{dt}+U_a=U_0 \tag{3-10}$$

hence

$$\left.\begin{aligned} L\frac{di}{dt}&=-(U_a-U_0)\\ L\frac{di}{dt}&=-\Delta U \end{aligned}\right\} \tag{3-11}$$

The structure of (3-11) is the same as that of (3-4). It determines the conditions under which the minimum possible time of field discharge may be attained. Therefore, the field discharge time can be brought close to its minimum value by properly choosing the performance characteristics of the field discharge device furnished with a deion grid.

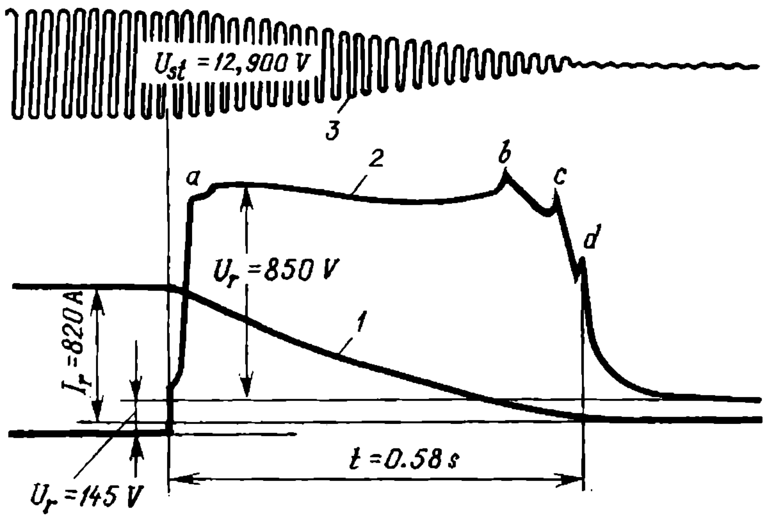


Fig. 3-12. Hydroelectric generator field discharging by FDC diagrammatically shown in Fig. 3-11 (field discharging oscillogram of 26.9 MW hydroelectric generator)

1 — excitation current; 2 — field coil voltage; 3 — stator terminal voltage

Oscillograms depicting the field discharge process by the FDC devices furnished with deion grids are shown in Fig. 3-12 for hydroelectric generators and in Fig. 3-13, for turbogenerators. When rotor currents are in excess of 600 amperes, two deion grids are used so that a double-pole break of the rotor winding circuit is provided.

The construction of a field discharge control for heavier currents is shown in Fig. 3-14. The magnetic field which pulls the arc into the grid after breaking the circuit by main contacts *3* is excited by series-connected coil *5*. The field makes the arc move along horns *6* to be pulled into deion grid *7* which is composed of copper plates isolated from one another. On entering this grid, the arc is broken up into a number of short arcs which are caused to rotate at very high speed by a radial magnetizing field built up by auxiliary coils *10*, thus

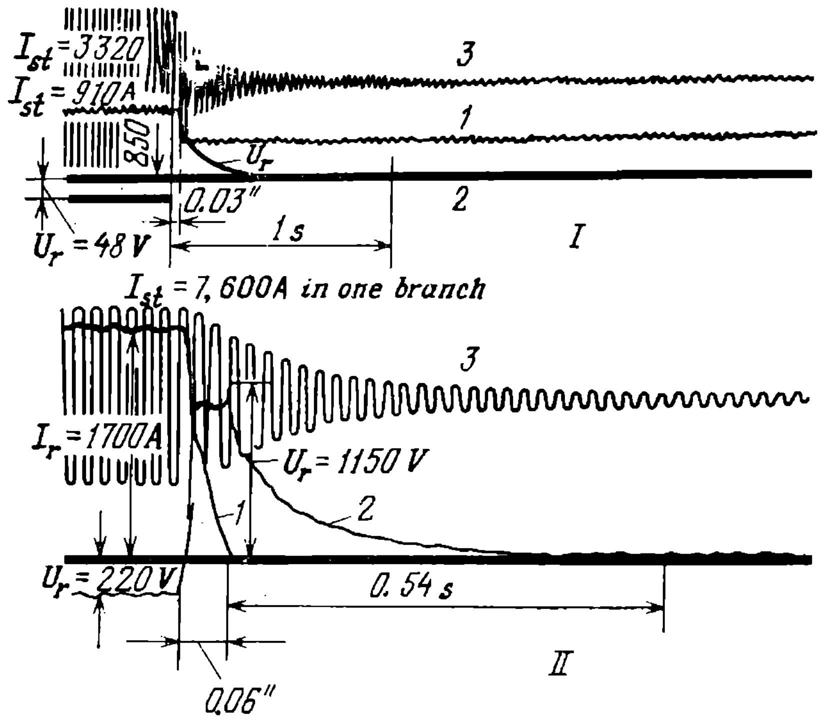


Fig. 3-13. Turbogenerator field discharging

I — 25 MW with short circuit; *II* — 200 MW under normal load; *1* — excitation current; *2* — rotor slip ring voltage; *3* — stator current

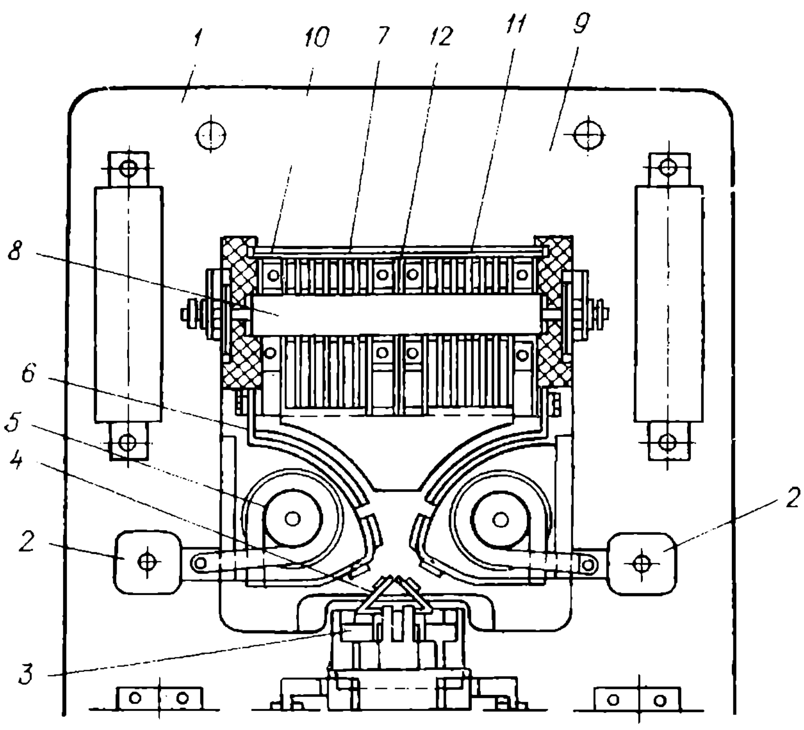


Fig. 3-14. Field discharge control unit with deion grid designed for heavy currents

1 — steel plate; *2* — current input terminals; *3* — main movable contacts; *4* — auxiliary movable contacts; *5* — cross-field extinguishing coils; *6* — arc extinguishing horns; *7* — deion grid; *8* — steel rod; *9* — steel casing; *10* — radial-field coil; *11* — bypass resistors; *12* — dead plates

preventing overheating and burning of the plate metal. Resistor *11* which provides by-pass for the individual sections of the grid prevents overvoltages the instant the arc is extinguished.

For the schematic diagram of the field discharge control see Fig. 3-15.

The circuit employed by the FDC with deion grid envisages insertion of a resistance in parallel with the excitation winding of a synchronous machine to allow for starting by the self-synchronizing method (see Chapter 7).

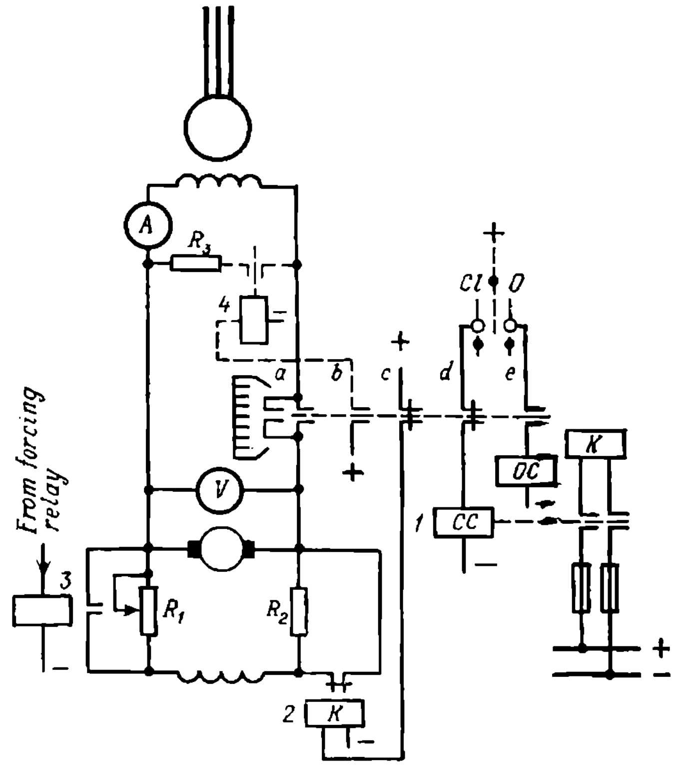


Fig. 3-15. Control of FDC unit furnished with a deion grid

a — main contact; *b-e* — blocking contacts; *1-4* — contactors; R_1 — regulating rheostat; R_2 — power limiting resistor cut in after the main contact of a FDC opens; R_3 — series resistor and *4* — contactor (these are installed to allow generator parallelling by the self-synchronizing method)

FDC devices with deion grids cannot break up small field currents because the spin of the arc is retarded in the deion chamber and the arc may not disintegrate with resulting damage to the deion chamber. Such faults occurred when attending personnel tripped the FDC after reducing the excitation current to 100 amperes or more. In this connection never discharge a field with an FDC-1 device used with generators rated at 100, 150 MW and more at currents less than no-load values and do not use the FDC-1 type devices for generators whose no-load current is less than 200 amperes.

Field discharge with gas-discharge tube and thyristor methods of excitation. The field discharge is accomplished by inverting the gas-discharge tube or thyristor exciter and simultaneously forcing the excitation. Such a mode of operation continuous until a current zero in the rotor winding. Then the mer-

cury-arc rectifier or thyristor converter is cut off. Control is accomplished without interrupting the current in the circuit.

The differential equation that describes the field discharge process is as follows

$$L\frac{di}{dt}+ir=-U_{\max} \tag{3-12}$$

If the voltage drop across the resistance of the rotor as compared to the

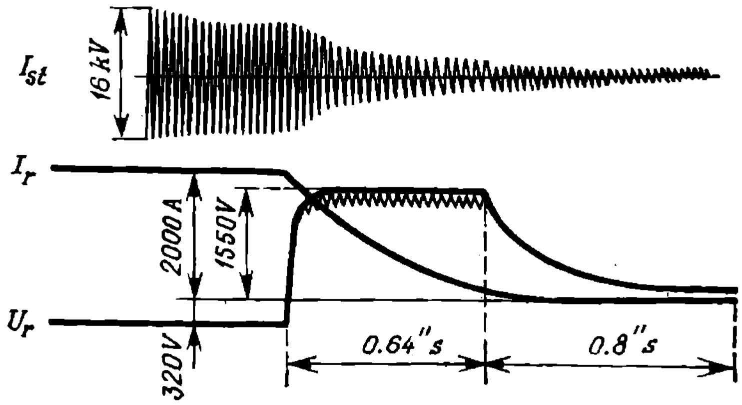


Fig. 3-16. Hydroelectric generator field discharging under no-load conditions when using gas-discharge tube excitation (the generator rating is 105 MW)

voltage value $U_{\max}$ may be neglected, then (3-12) takes the form

$$L\frac{di}{dt}=-U_{\max} \tag{3-13}$$

and becomes similar to (3-4) which is the condition decisive for the quickest field discharge.

Figure 3-16 shows a typical oscillogram of the field discharge process.

3-6. Conclusions

1. The excitation systems of synchronous machines must possess the lowest inertia possible, the most rapid response and the highest excitation ceiling.
2. The excitation systems of synchronous machines must ensure high reliability of operation. A fault in the excitation system causes the generator to stop and may result in an outage of the power system. The most promising are the gas-discharge tube and thyristor excitation systems and the circuits utilizing solid-state rectifiers with high-frequency generators.
3. Field discharge automatic devices are necessary components in automatic control systems.

The field discharge circuit must enable the machine to connect by the self-synchronizing method.

4. Promising is the design of exciters with a brushless excitation system as it materially improves reliability.

5. All other things being equal, the FDC devices, quickest in discharging the field to the residual voltage value at which the arc extinguishes itself, are preferable as they possess better reliability.

6. Developed in the USSR are field discharge units having deion grids and voltage invertion of a gas-discharge tube or thyristor exciter with simultaneous forcing so that minimum field-discharge time may be attained.

3-7. Review Questions

1. Describe the schemes used for excitation of synchronous machines. What is the difference between the dynamoelectric separate excitation and self-excitation systems?

2. How is excitation forcing obtained with various excitation systems when the stator terminal voltage of a synchronous machine droops?

3. Desribe the excitation devices of large rated turbogenerators.

4. What are the differential equations describing the transfer field discharge process for the excitation systems utilizing dynamoelectric, gas-discharge tube and deion grid principles?

5. What are the conditions for obtaining the minimum field discharge time? What are the specific features encountered in the operation of a field-discharge unit using deion grid?

6. What are the principal gas-discharge tube excitation circuits? How is the excitation orcing operation accomplished where a mercury-arc rectifier forcing group is available?

7. What is the purpose of the double-pole break of the excitation circuit when use is made of field-discharge control having a deion grid?

8. Determine the field discharge time for a hydroelectric generator rated at 13,000 to 15,000 volts which is idling under the following conditions: the circuit utilized by the *FDC* is as in Fig. 3-1; the dynamoelectric exciter voltage, U_0 is 345 volts; the rotor insulation test voltage, U_{test} is 3,500 volts; the rotor winding resistance, r is 0.168 ohm; the rotor winding inductance in the unsaturated portion, L is 0.806 H; the resistance connected in parallel to the rotor winding R is four times r; the field current initial value, I_0 is 2,050 A; and the residual voltage across the stator terminals after the field discharge process has been completed, U_{res} is 200 volts.

Solution. 1. According to (3-2) the equation describing the field discharge process is $i = I_0 e^{-t/\tau_1}$[3-7]

Here

$$\tau_1 = \frac{L}{R+r} = \frac{L}{r(k+1)}$$

For the example under consideration

$$k = \frac{R}{r} = 4$$

and

$$\frac{L}{r} = \tau = \frac{0.806}{0.168} = 4.8 \text{ s}$$

2. The time it takes to complete the field discharge process

$$t = \frac{\tau}{k+1} \ln \frac{I_0}{i_r}$$

where the rotor winding current i_r corresponds to the residual voltage U_{res} at which the arc extinguishes itself

$$\frac{i_r}{I_0} = \frac{U_{res}}{\sqrt{2}\, U_{m.v}}$$

where $\sqrt{2}\ U_{m.v}$ is the amplitude value of the maximum voltage across the stator terminals of the generator under no-load conditions.

Thus

$$\frac{I_0}{i_r}=\frac{\sqrt{2}\,U_{m.v}}{U_{res}}=\frac{\sqrt{2}\cdot 15{,}000}{200}=105$$

and

$$t=\frac{4.8}{4+1}\ \ln\ 105=\frac{4.8}{5}\cdot 4.6=4.4\ \text{s}$$

9. Using the data of the foregoing example, calculate the minimum possible field-discharge time when constant voltage equal to the value of the test voltage, U_{test} = 3,500 volts, must be maintained across the rotor winding terminals during the discharging process.

Solution. In compliance with (3-6)

$$t_{min}=I_0\,\frac{L}{U_{test}}$$

$$t_{min}=2{,}050\,\frac{0.806}{3{,}500}\ \text{is about } 0.5\ \text{s}$$

10. Using the data given in example 3-9, determine the field discharge time when use is made of a *FDC* device having a deion grid composed of 75 plates. Let the voltage between the plates be equal to 30 volts.

Solution 1. We first determine the voltage across the arc in the deion grid after the field discharge control has tripped

$$U_a=30\cdot 75=2{,}250\ \text{V}$$

2. And then in accordance with (3-11)

$$L\,\frac{di}{dt}=-(U_a-U_0)=-(2\ 250-345)$$

$$L\,\frac{di}{dt}=-1{,}905$$

hence

$$t=I_0\,\frac{L}{\Delta U}=2{,}050\,\frac{0.806}{1{,}905}=0.86\ \text{s}$$

10. What is the difference between the thyristor excitation systems and the excitation systems utilizing gas-discharge tubes?

11. What is the operating principle of the brushless excitation system?

12. What is the purpose of the forced excitation limiter used in excitation control devices?

Chapter Four

AUTOMATIC CONTROLS FOR MAINTAINING STABILITY IN PARALLEL OPERATION AND ELIMINATION OF ASYNCHRONOUS OPERATION

4-1. General

The building of large power grids, the increased power output of individual generating units and electric power generating stations, the long heavily loaded transmission lines and joint operation of paralleled power systems through "weak" links have imposed a series of requirements upon automatic power control systems. They are:

(a) Maximum possible transmission capacity must be ensured on transmission lines.

(b) Disturbances to the stability of the power systems operating in parallel must be prevented.

(c) In case of asynchronous operation it should be rapidly stopped and conditions established for normal power supply to consumers.

These requirements are met by a group of automatic devices sometimes called automatic mode controls. The compulsory use of these devices and the necessity of taking them into account when calculating stability are fully explained in appropriate publications[4-1].

In recent years, to improve the steady-state stability of turbogenerators, besides the AEC devices considered above automatic devices to limit active power transfers (due to circulating currents) by acting upon the turbine governor system were developed. In many cases dangerous transmission line overloads are eliminated by automatically disconnecting some generators at the power supplying stations.

The first way to improve transient stability is to quickly clear short circuits and also just as quickly reduce steam turbine power for a short time ("strong power regulation"), disconnect some of the generators or apply emergency braking.

If the measures taken to prevent stability disturbances are not effective and asynchronous operation occurs, it can be eliminated by using automatic sectionalizing devices. Different variants of these devices can sectionalize the power system into roughly balanced loads either instantaneously or within a certain period after the asynchronous situation occurred.

Restoration of synchronism in the power system may be attained by resynchronization of the paralleled generators either spontaneously after a short-time or continuous asynchronous operation, or it may be effected by the automatic

controls which sense the change in the active power generated and taken by individual parts of the power system.

It should be noted that power system faults affecting stability are most dangerous and they may interrupt the supply to consumers for long periods. For this reason, in addition to the use of a number of automatic devices, special instructions stipulate that attending personnel shall eliminate asynchronous operation by sectionalizing the power system at predetermined points if the duration of asynchronous run exceeds 2 minutes[4-2] or if prolonged asynchronous operation adversely affects performance of the main equipment with possible damage to it.

4-2. Principal Relations Determining Operation of Automatic Controls

According to (1-3) the active electric power transmitted from a finite power station over a transmission line to an infinitely (unlimited) large power system

$$P = \frac{UE_d}{x_{12}} \sin \delta. \tag{4-1}$$

The graphical relationship (4-1) is illustrated by the sine curve in Fig. 4-1. Power transmission under normal operating conditions is carried out at the angle δ_n determined by point *a* on the abscissa where it intersects sine curve *1* which is the electric power characteristic and straight line *3* which is the turbine power characteristic corresponding to the load required by the consumer at the receiving end of the power system.

The transmission *steady-state* stability limit is determined by the maximum value of the electric power P_{max} when $\delta = 90$ degrees. Under normal operating conditions at least a 20-per cent steady-state stability margin must be provided along the transmission lines connecting the power station with the power distributing system[4-1].

It is evident from (4-1) that the steady-state stability may be disturbed either during a smooth decrease in the generator voltage (emf) or the voltage at the receiving end or during a slow increase in the power being transmitted due to the rise in the turbine power as the angle δ gradually reaches 90 degrees which then disturbs the balance between the turbine power and the electric power of the generator.

When the voltage *abruptly* drops due to a short circuit or when the mutual resistance between the power station and the power system *suddenly* rises as the operating conditions are changed (during a short circuit or after disconnection of some transient links), the stability may be disturbed even after clearing the short circuit. The possibility of maintaining stability depends both on the duration and amount of the initial disturbance and on the operating conditions set up after the fault. These factors, which cause sudden changes in the operating conditions, determine the transient (*dynamic*) stability of the power station.

With unexpected changes in electric power (due to disconnection of one of the transmission lines or a short circuit) and a change from curve *1* to curve *2*, the speed governor of the turbine has no time to instantaneously change the admission rate of water or steam. A discrepancy arises between the power of the prime mover and the electric power produced by the generator. The latter gains speed causing an increase in the angle δ. The powers of the prime mover and generator are balanced at point *c*. The rotor, however, continues to rotate due to inertia and the electric power becomes greater than the power of the

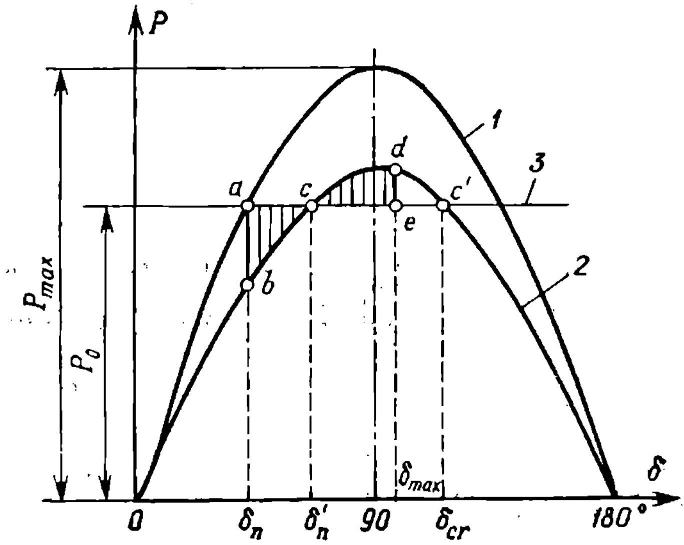


Fig. 4-1. Power characteristic when generator works into the busbars of an infinite power system

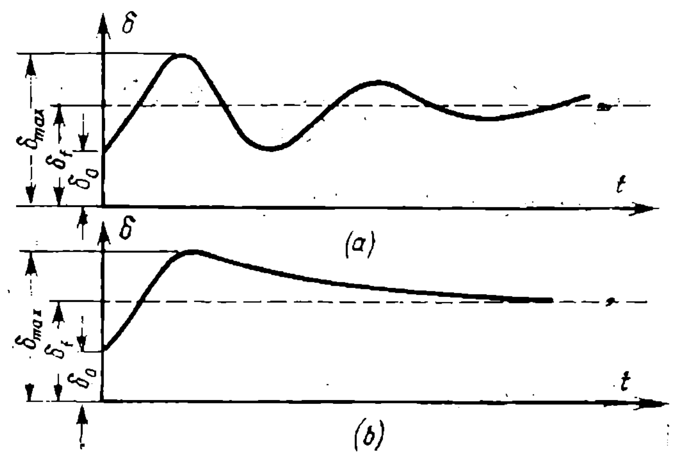


Fig. 4-2. Variation of angle δ between emf vectors versus time when synchronism is sustained

turbine, and the generator starts decelerating. After several decaying swings the angle δ becomes equal to the angle δ_n' corresponding to a new steady-state condition determined by the power balance of the prime mover and the generator.

Another case will be if the angle δ becomes greater than the critical angle δ_{cr} on the drooping leg of the characteristic curve *2*. In this event, the excessive torque changes its sign and causes further acceleration of the rotor. The machine loses its synchronism and operates asynchronously. Synchronism will be preserved, if the accelerating area S_{abc} does not exceed the decelerating area $S_{cdc'}$ (see Section 4-4).

Tentative time of eliminating a short circuit in order to preserve transient stability may be determined from the following. Suppose that under short-circuit conditions the generator throws off the load completely (three-phase short circuit) and the turbine speed governors have no time to change the water or steam supply. The excessive turbine power induces an excessive torque moment on the motor shaft equal to

$$\Delta M \approx \frac{\Delta P}{\omega_n} = \frac{P_{load}}{\omega_n} \qquad (4\text{-}2)$$

The approximation symbol $\approx$ is used because the angular velocity ω_n is assumed constant and equated with the nominal value corresponding to the frequency of 50 Hz.

The acceleration of the relative rotor speed is proportional to the value ΔM of the torque applied and inversely proportional to the inertia J of the generating unit (the generator and

the turbine)

$$\alpha=\frac{d^2\delta_{12}}{dt^2}=\frac{\Delta M}{J} \tag{4-3}$$

or

$$\frac{d^2\delta_{12}}{dt^2}=\frac{P_{load}}{J\omega_n} \tag{4-4}$$

where ω_n is the nominal value of the angular velocity.

The inertia constant

$$T_{in}=\frac{J\omega_n^2}{P_n} \tag{4-5}$$

where P_n is the nominal power of the generator.

The expression (4-4) may be rewritten as follows:

$$\frac{d^2\delta_{12}}{dt^2}=\frac{P_{load}}{P_n}\cdot\frac{\omega_n}{T_{in}} \tag{4-6}$$

Considering that the change of angular velocity

$$\Delta\omega=\frac{d\delta_{12}}{dt}=\frac{P_{load}}{P_n}\cdot\frac{\omega_n}{T_{in}}t, \tag{4-7}$$

we obtain

$$\frac{\Delta\omega}{\omega_n}=\frac{1}{T_{in}}\cdot\frac{P_{load}}{P_n}t \tag{4-8}$$

Variation of the relative angle is

$$\delta_{12}=\frac{1}{2}\frac{P_{load}}{P_n}\cdot\frac{\omega_n}{T_{in}}t^2 \tag{4-9}$$

The inertia constant T_{in} of the units (generator and turbine or motor and driven mechanism) is determined by the design parameters of the machines and their speed of revolution

$$T_{in.\,unit}=\frac{2.74GD^2n^2}{P_{unit}}10^{-3}\ \mathrm{s} \tag{4-10}$$

where GD^2 = moment of gyration, $\mathrm{t\cdot m^2}$

n = speed of the unit, rpm

P_{unit} = nominal power of the unit, MW

The inertia constants of the units (generator and turbine or motor and driven mechanism) are determined as the sum of the inertia constants of the generator $T_{in.\,gen}$ and the turbine $T_{in.turb}$ or of the motor $T_{in.mot}$ and the mechanism $T_{in.\,mech}$.

If the inertia constants are reduced to a base power, the recalculation is performed

$$T_{in.\,basis}=T_{in}\frac{P_n}{P_{basis}} \tag{4-11}$$

It is convenient to express the relative angle δ_{12} in degrees. Then we obtain from (4-9)

$$\delta^{\circ}_{12}=2\pi f\,\frac{360}{2\pi}\,\frac{1}{2T_{in}}\,\frac{P_{load}}{P_n}t^2 \tag{4-12}$$

At a frequency f = 50 Hz

$$\delta^{\circ}_{12}=9{,}000\frac{1}{T_{in}}\cdot\frac{P_{load}}{P_n}t^2 \tag{4-13}$$

The change in the angle δ from one value (initial) to another (final) under maintained synchronism occurs after several synchronous swings (Fig. 4-2*a*) or aperiodically (Fig. 4-2*b*).

If during transient operation the angle δ exceeds 180 degrees asynchronous running occurs and the angle δ periodically changes from 0 to 360 degrees. In asynchronous operation the electrical variables (current, voltage, power carried by the transient links) alternately vary their quantities from the minimum to the maximum in conformity with the time variations of the angle δ. When out of synchronism, along with the alternating synchronous torque, an asynchronous torque appears which is dependent upon the amount of slip, i.e., the difference between the frequencies of the system and the generator, and the construction of the out-of-step machine. At certain relationships of these torques and due to the operation of the turbine speed governors, resynchronization may occur, i.e., recovery of the synchronous parallel operation, after several asynchronous revolutions when the speed of the station generators approximates the synchronous value.

Asynchronous operation with subsequent resynchronization may be either short-time, only a few seconds, when resynchronization takes place after one to three asynchronous revolutions, or prolonged. In a number of instances resynchronization may not occur at all. Resynchronization occurs, if the steady slip between the system parts fallen out of synchronism becomes less than the so-called critical slip whose value depends upon the total reactance between these parts. The critical slip value is 1.5 to 2.0 Hz for fairly "rigid" couplings (small reactances), and from 0.2 to 0.5 Hz for "weak" couplings (relatively great reactances) between these parts of the system. Techniques for determining the critical slip are dealt with in[4-4], which also covers power system resynchronization problems.

Generally, with complicated composite power systems, resynchronization is not aimed at, as the mission of pulling into synchronism is assigned to so-called automatic sectionalizing devices which separate the power system into sections at predetermined points.

These measures are resorted to for the following reasons:

(a) When one part of the power system operates asynchronously with respect to another one, the voltage variations at various points may disturb the stability of the other parts of the system thus resulting in a complicated form of multi-frequency asynchronous operation.

(b) A voltage decrease at the points near the electric centre of the system may disturb the stability and disconnect substantial number of synchronous and asynchronous motors used by consumers.

(c) For certain types of load and apparatus asynchronous operation is not allowed.

For the operation analysis of automatic devices it is important to know the type of changes occurring in the electrical quantities due to changes in the angle δ.

Variations of the electrical magnitudes during synchronous swings and under asynchronous running differ from their changes caused by short circuits. The difference is as follows.

During synchronous swings and asynchronous running the electrical variables depend on the angle between the emf vectors of machines operating in parallel and are changed smoothly in time. With short-circuit faults these changes are sudden and stepwise.

At heavy loads, and in the case of swings and synchronous running, all the electrical quantities are symmetric if there are no asymmetric transient couplings and/or asymmetric loads. Asymmetry of electrical quantities always

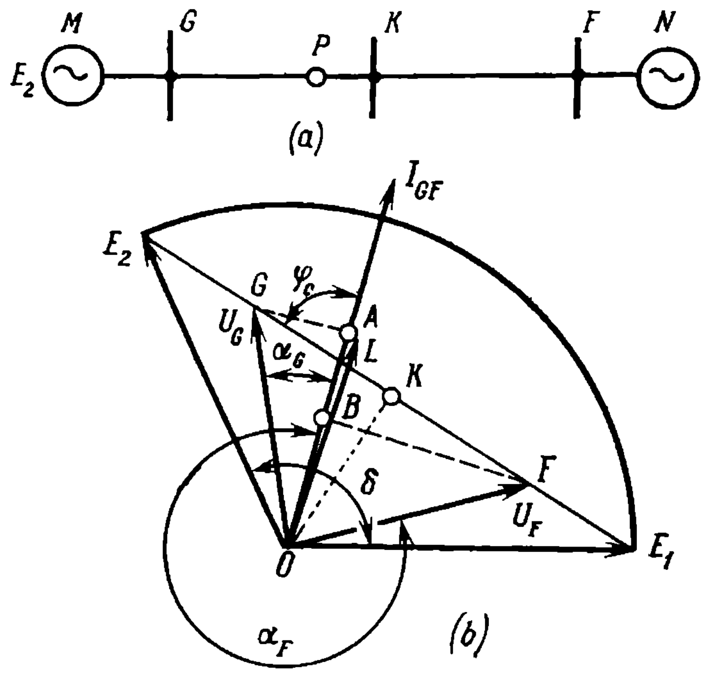


Fig. 4-3. Elementary system

(a) network diagram; (b) circuit currents and voltages when emf vectors are parted through angle δ

$$AG = LG \sin \varphi_C = x_{1LG}$$

$$BF = LF \sin \varphi_C = x_{1FL}$$

$$\alpha_G = \arcsin \frac{I_{GF} x_{1LG}}{U_G}$$

$$\alpha_F = \arcsin \frac{I_{GF} x_{1EL}}{U_F}$$

takes place with short-circuit faults. With asymmetric short circuits the asymmetry of electrical quantities persists the whole short-circuit period. Under three-phase short-circuit conditions the asymmetry on the terminals of the secondary relays occurs at the beginning of the fault, since the phases are not short-circuited simultaneously, and also due to the aperiodic components of the short-circuit currents and transient processes in the circuits of the symmetric component filters by means of which the relays are connected to current or potential transformers.

To elucidate the basic relationships, let us consider an elementary system (Fig. 4-3a) including two power stations, M and N, operating in parallel and

connected by line GF. To simplify the analysis, assume that $|\dot{E}_1| = |\dot{E}_2| = |\dot{E}|$ and that the impedance between the points to which the emf is applied is distributed uniformly.

If the emf vector of the N generators is constant in value and direction, then the emf vector of the M generators may be expressed as a function of the angle δ between the emf vectors (Fig. 4-3b) as follows

$$\dot{E}_2 = \dot{E}_1 e^{j\delta} \tag{4-14}$$

The absolute value difference between these emf's

$$|\Delta\dot{E}| = |\dot{E}_2 - \dot{E}_1| = |\dot{E}_1(e^{j\delta} - 1)| = \Delta E_M \sin\frac{\delta}{2} = 2E\sin\frac{\delta}{2} \tag{4-15}$$

where ΔE_M is the maximum value of the emf difference (when $\delta = 180$ degrees).

Because of the effect of the emf difference $\Delta\dot{E}$, current flows between the generators

$$\left.\begin{aligned} \dot{I}_{GF} &= \frac{\Delta\dot{E}}{z_{1MN}} \\ \dot{I}_{GF} &= I_{GF_M}\sin\frac{\delta}{2} = \frac{2E}{z_{1MN}}\sin\frac{\delta}{2} \end{aligned}\right\} \tag{4-16}$$

where I_{GF_M} is the maximum value of the equalizing current (when $\delta = 180$ degrees).

Here z_{1MN} is the forward sequence impedance of the line between points M and N.

In space the vectors of currents in phases A, B and C form a symmetric star.

The voltage at a random point P (Fig. 4-3)

$$U_P = E\sqrt{\cos^2\frac{\delta}{2} + \left(2\,\frac{z_{1PK}}{z_{1MN}}\sin\frac{\delta}{2}\right)^2} \tag{4.17}$$

where z_{1PK} is the forward sequence impedance between point P and point K located in the *electric centre*, i.e., at the system point at which the voltage equals zero when the emf vectors are at the angle $\delta = 180$ degrees.

The voltage at the electric centre K of the system (Fig. 4-3b)

$$U_K = E\cos\frac{\delta}{2} \tag{4-18}$$

When the generator emf's are equal, the electric centre is the midpoint of the line, provided there are equal impedances on both sides from point K to points M and N to which the emf is applied.

The system has a "zero reactance" point at which the angle between the current and voltage of the corresponding phase is zero (point L in Fig. 4-3b). Location of this point is of interest for the analysis of the performance of the directional protection means and the inductive reactance relays.

From the above-mentioned relationships it follows that the currents, voltages and the phase displacement between the current and voltage may be different for different points when the generator emf vectors of the stations operating in parallel are shifted relative to each other.

4-3. Automatic Controls for Improvement of Steady-State Stability

As can be seen from expression (4-1), the critical value of the active power sent over a transmission line can be increased if the emf value E_d or the busbar voltage U of the receiving substation rises, or if the mutual reactance x_{12} decreases.

As mentioned in Chapter 1, the increase of the value E is controlled by the excitation regulators which are essential components improving the steady-state stability o fpower systems. Other types of automatic devices adding to the steady-state stability are load limiting devices on tie transmission lines and the devices which unload the power transmission system when the amount of power being transmitted approaches the critical value.

Active power flow is limited by power flow regulators and limiters (see Chapter 6). The time taken to execute the control signal and remove the load from the tie line ranges from 30 to 60 seconds (Fig. 4-4). The power flow limiters adjust the steam inlets to the turbines through the usual or special type regulators which can stop the steam flow to the turbine immediately.

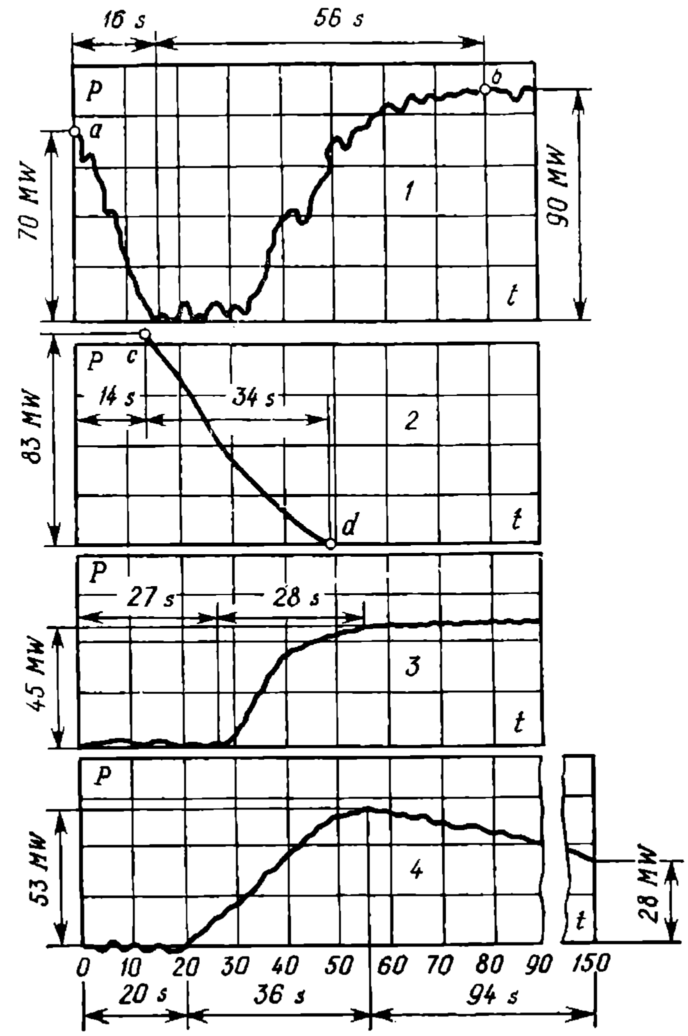


Fig. 4-4. Processes in automatic limiting of power flows

1 — changes in power flow over transmission line; *a* — instant at which mismatch develops between actual power flow and setting of limiter; *b* — instant at which the assignment is executed; 2 — limiter operation; c — beginning of output signal; *d* — end of signal; 3 — changes in power of the first regulating hydroelectric power station due to the action of limiter signal (a process without overshooting); 4 — the same at the other hydroelectric power station (a process with overshooting)

Devices that rapidly unload the tie lines by automatically disconnecting some supplying station generators are very popular. Hydroelectric generators are the easiest to disconnect. Disconnection of turbogenerator-transformer units needs correct coordination between the unloading automatic controls and automatic heat engineering devices which provide continuous operation of the house circuits being supplied from the unloaded generator.

Sensing units which respond directly to the value of the angle δ or to the electrical parameters dependent upon the value of angle δ may be used as detecting elements of the automatic unloading devices. The most simple way is to utilize a relay responding to current, active power or impedance.

Unloading automatic devices utilizing current relays. These incorporate relays with series-connected contacts handling the A, B and C currents (Fig. 4-5).

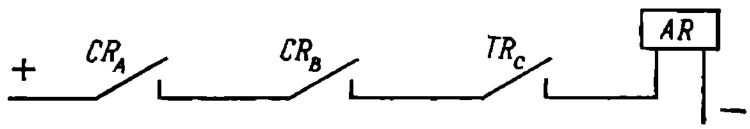


Fig. 4-5. Unloading automatic device made up of current relays
CR_A, CR_B and CR_C are current relay contacts connected into phases A, B, and C.

This type of connection prevents objectionable functioning caused by asymmetric short circuits making it possible to use the relay pick-up setting corresponding to the permissible angle δ for the critical load. Malfunctions of these automatic devices are possible if three-phase short circuits, which are very rare, occur (less than 0.5 per cent of the total number of faults).

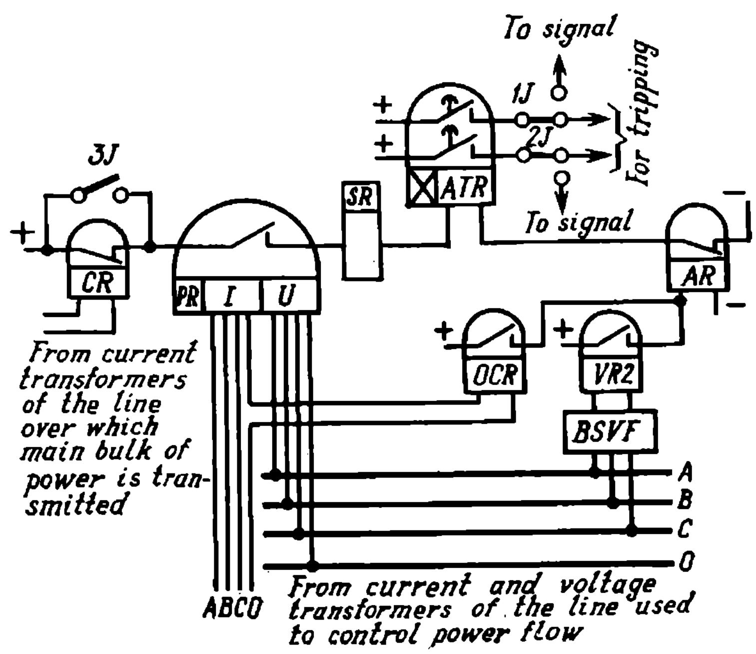


Fig. 4-6. Unloading automatic device made up of active power relays

Unloading automatic devices utilizing active (real) power relays. Active power relays are connected to handle either the phase power, forward sequence power, or the total three-phase power (Fig. 4-6). When this device is used provision should be made in its circuit to prevent malfunctions caused by a rise in the active power during a short circuit (active power losses in the arc and transmission lines). Often the circuit is made with a blocking relay responding to

asymmetry, i.e., a relay which functions in the case of a backward or zero (phase) current or voltage sequence.

The operating settings of the real power relays must correspond to an angle $\delta_{pick\text{-}up} = 0.8\delta_c \approx 70$ degrees (Fig. 4-1). The operating setting of the current relay used in the device shown in Fig. 4-5 may be oriented towards an angle δ somewhat greater than that used in the power relay, as the real power decreases

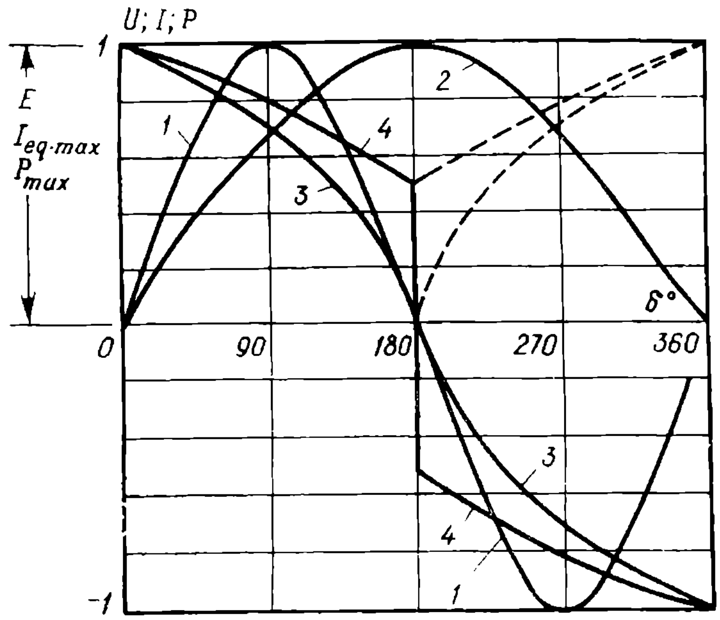


Fig. 4-7. Changes in values of real power (*1*), current (*2*) and voltage (*3*) and (*4*) on individual lengths of tie link of elementary system (*3*—in electric centre; *4*—at point *P* of circuit as in Fig. 4-3*a* when $z_{1PK}/z_{1MK} = 0.5$; resistance of power transmission line is neglected, it being assumed that $R_{MN} = 0$)

when the angle δ exceeds 90 degrees and the result may be a failure in the work of the power relay, while the current grows until the angle δ reaches 180 degrees (Fig. 4-7).

A disadvantage when applying the unloading automatic devices, utilizing current relays or real power relays, is that the operation of these relays depends not only on the angle δ but also on voltage. The designed pick-up setting of the relay must correspond to the pick-up angle $\delta_{pick\text{-}up}$ at the lowest voltage at the ends of the transmission system under normal operating conditions. If the voltage and the emf are maintained at high values, then in conformity with (4-1), the maximum power (current) corresponding to the maximum $\delta_m = 90°$, as dictated by the steady-state stability requirements, increases. Consequently, the automatic devices adjusted to a current or active power value at the minimum level of voltage or emf do not allow the load-carrying capacity of the tie line system to be fully used. It is better to supplement or replace the automatic devices utilizing current or active power relays with relays responding to impedance values or with directional impedance relays.

Unloading automatic devices with directional impedance relays. One of these devices is illustrated in Fig. 4-8. Current relays ensure operational selectivity

against asymmetric short circuits and prevent malfunctions from faults in the potential transformer circuits to which the directional impedance relay is connected.

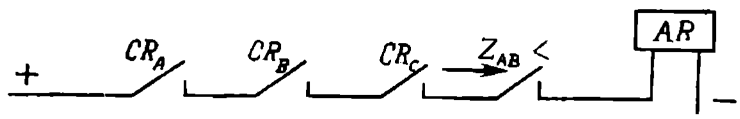


Fig. 4-8. Unloading automatic device employing directional impedance relay
CR_A, CR_B and CR_C are current relay contacts; Z_{AB} is the contact of impedance relay

According to (4-16) and (4-17) the impedance across the terminals of the impedance relay installed at point P of the tie line

$$z_P = z_{1MK} \cot\frac{\delta}{2}\sqrt{1+\frac{z_{1PK}}{z_{1MK}}\tan^2\frac{\delta}{2}} \qquad (4\text{-}19)$$

From (4-19) it follows that the impedance measured by the relay installed in the electric centre ($z_{1PK} = 0$) is nearly directly proportional to the angle δ (Fig. 4-9) when this angle varies from 45 to 315 degrees (δ = 45-315°). If the relay is installed at another point of the tie line, the impedance measured by it within the above angle range does not depend on the voltage although it is not directly proportional to the angle δ. Almost direct proportionality to the angle δ may be obtained by imposing upon the impedance relay a voltage which is compensated up to the electric centre.

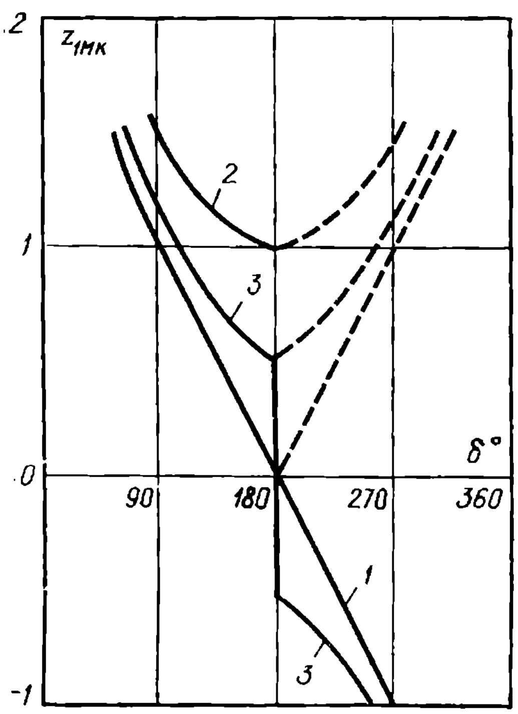


Fig. 4-9. Variation of terminal impedance of impedance relay versus angle δ and points of installation in elementary system

1 — in electric centre; 2 — at point of emf application; 3 — at point P between points M and K of elementary system in Fig. 4-3a when $z_{1PK}=0.5\, z_{1MK}$. Shown in broken line are absolute values of z_{1P} as functions of δ within the range from 180 to 360°, $z_{1P}=f(\delta)$

The use of a directional impedance relay with a properly selected setting in the detecting element of the automatic control system in place of an active power relay can be substantiated as follows. The pick-up setting of the power relay of the unloading automatic control is found from the expression

$$P_{pick\text{-}up} \approx 0.8P_m \approx 0.8\,\frac{E_{g\cdot ph}U_{ph}}{x_{12}} \approx 0.8\,\frac{U^2_{ph}}{x_{12}} \qquad (4\text{-}20)$$

The active power across the power relay terminals (per phase)

$$P = U_{ph} I \cos\varphi \qquad (4\text{-}21)$$

The relay functions, if the active power $P > P_{pick\text{-}up}$. With due consideration to the above, the equation may be written

$$U_{ph}\, I \cos\varphi = 0.8\frac{U^2_{ph}}{x_{12}} \qquad (4\text{-}22)$$

Hence

$$\frac{U_{ph}}{I \cos \varphi} = \frac{x_{12}}{0.8} = 1.25 x_{12} = \text{const} \qquad (4\text{-}23)$$

or

$$z/\cos \varphi = \text{const} \qquad (4\text{-}24)$$

Expression (4-24) is characteristic of the directional impedance relay whose diameter coincides with axis R. The diameter

$$D = 1.25 x_{12} \qquad (4\text{-}25)$$

The characteristic circle is tangent to the axis of ordinates (Fig. 4-10).

It is seen from (4-25) that the pick-up setting of the directional impedance relay is constant and independent of the operating voltage, i.e., the relay adjusts itself to the voltage

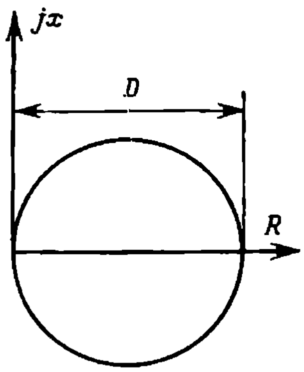


Fig. 4-10. Characteristic of cosine-type directional impedance relay

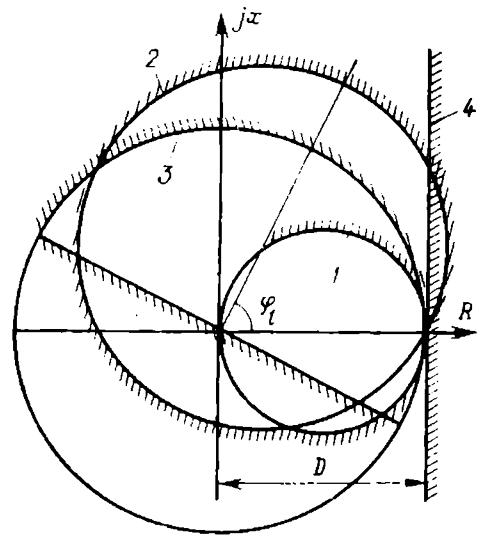


Fig. 4-11. Characteristics of detecting element

1 — cosine-type directional impedance relay; *2* — directional impedance relay with internal angle equal to impedance angle φ_l; *3* — impedance relay and directional power relay (series-connected contacts); *4* — resistance relay

value existing at each moment. As compared with the use of a real (active) power relay, the detecting element utilizing a directional impedance relay offers a gain in transmitted power which amounts to 5-10 per cent of the maximum power that can be transmitted [4-5].

It should be noted that the unloading automatic devices may utilize impedance relays having not only a characteristic satisfying the condition (4-25) (Fig. 4-11, circle *1*), but also other characteristics, *2*, *3* or *4*, for example. The only requirement is that he relay functions within the region along the R axis with $R \leqslant D$. At angles $\delta = 180$ degrees, the phase relations between the current and voltage are the same as for a three-phase short circuit at the electric centre. Therefore, the directional impedance relays, generally used for distance protection, take measurements (with $\delta = 180°$) corresponding to the terminal impedance of the relay during a three-phase short circuit at the electric centre. This property has been used by the "Energoset" design agency for selective location of the electric centre in multibranch networks connecting several generating units and for automatic isolation of power stations fallen out of step.

Automatic unloading when the tie link weakens. From equation (4-1) it is clear that the maximum value of the power being transmitted decreases when one or several tie links are disconnected. This is due to an increase in the x_{12} value. To prevent disturbances to the stability, the batteries of lengthwise capacitance compensation (if available) are forced. The result is a decrease in the reactance x_{12} or the transmission line is unloaded to a value corresponding to the post-fault power limit.

To automatically unload the tie link, when the reactance x_{12} rises (because of disconnection of one of two parallel circuits, for instance), either the local effect from the switch of the disconnected circuit is used (from the auxiliary contacts of the switch or from the contacts of the repeater relay) or a telemetered pulse is sent to disconnect or unload the generators in the transmitting portion of the power system. Execution of this control pulse is generally accomplished by controlling the power being transmitted before the disturbance.

Sometimes a disturbance in tie line operation may be indicated by an inrush of zero or backward sequence current (Fig. 4-12). It should be kept in mind, however, that such a device may operate unselectively when short circuits happen in regions close to the tie line substations in the receiving part of the power system (for example, at the places with low-tension equipment), if the zero (backward) sequence current exceeds the operating current of the detecting element. This method, however, may be used if a spinning reserve exists at the receiving part of the power system or the power capacity of the system is such that unselective disconnection or unloading of the generators at the station supply side is permitted.

The operating principle of a selectivity device in an automatic unloading system, that functions when a section of the tie link is isolated, is illustrated in Fig. 4-13. Disturbances are indicated by operation of the protective relaying devices, which disconnect the defective element and simultaneously send an unloading signal (Fig. 4-13*a*). When a fault occurs at the section close to the station busbars the generators are disconnected directly. A remote-control breaking device is used when faults occur at remote sections.

The value of real power flow at which the unloading operation is allowed is controlled by the real power relay *1R* (three-phase or active power of forward sequence). This relay keeps its contacts open if the power flow value is greater than the pick-up setting. The relay *2ATR* "stores" the picked-up state of the relay *1R* during operation preceding the disturbance. The capacitor *4C* and resistor *5R* form a spark-killer network protecting the contacts of relay *1R* against burning and giving the *2ATR* a functional lag in case power rises in excess of the setting of relay *1R* when a short circuit occurs in the tie lines through an arc. This functional delay overlaps the protection operating time and is about 0.5 s. The resistor *3R* connected in series with the coil of the relay *2ATR* prevents the operational current circuit from "short-circuiting", when the contact of relay *1R* is closed.

Figure 4-13*b* shows the circuit of the unloading device with the tie line isolated, the circuit being started by a position relay that controls the opened position of the line switch (a *3SPR* relay). The purpose of the relay *1AR* is to

deenergize the output circuits of the device when the switch is disconnected for repair purposes to perform operations on these circuits with the current flow interrupted. The *2ATR* relay sends a momentary control pulse (within 0.3 to 0.5 s) for disconnection[1-4].

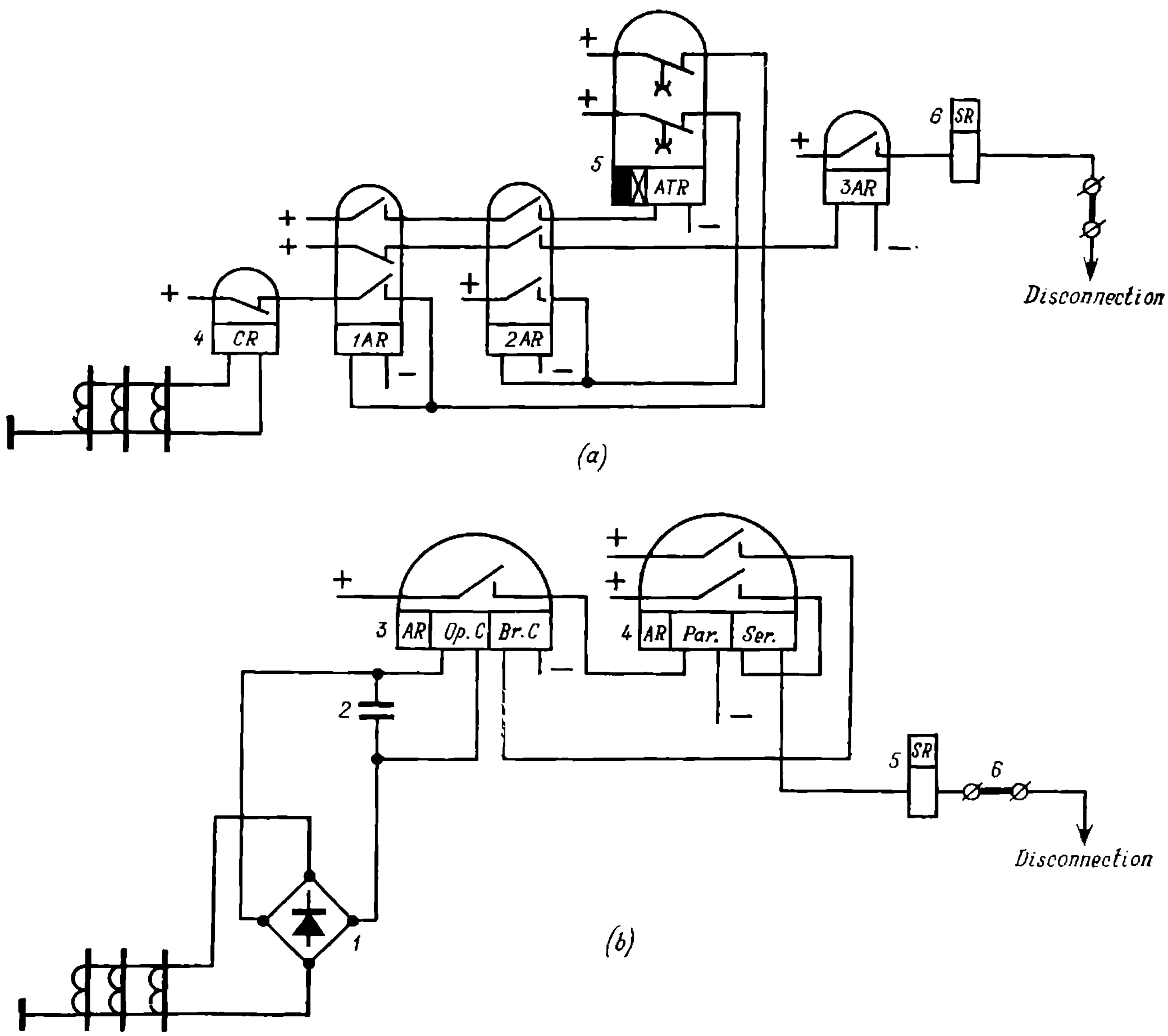


Fig. 4-12. Circuits responding to inrush of zero-sequence current

(*a*) with the type ЭТ relay; (*b*) with a high-speed d.c. relay. Relay *2AR* prevents misoperation after a short-time disturbance in operating current circuit

The circuit shown in Fig. 4-13*b* is more complicated than that in Fig. 4-13*a*. It produces an output signal when the protective relaying system may be inoperative, for example, if the line is disconnected manually.

Rapid remote-trip device. The rapid response time (less than 0.1 s) and elimination of interference in remote-control disconnectors are obtained by the use of a frequency-time code. Under normal operating conditions the transmitter of the remote-trip device continuously generates a carrier-frequency (c-f) signal

which is picked up by a receiver. Loss of the signal for 3 to 5 seconds or more indicates a fault in the c-f channel. When this occurs, the output circuits at the receiving end automatically open and a warning signal is sent to the operators. Functioning of the starting element of the remote-trip (*RT*) device changes

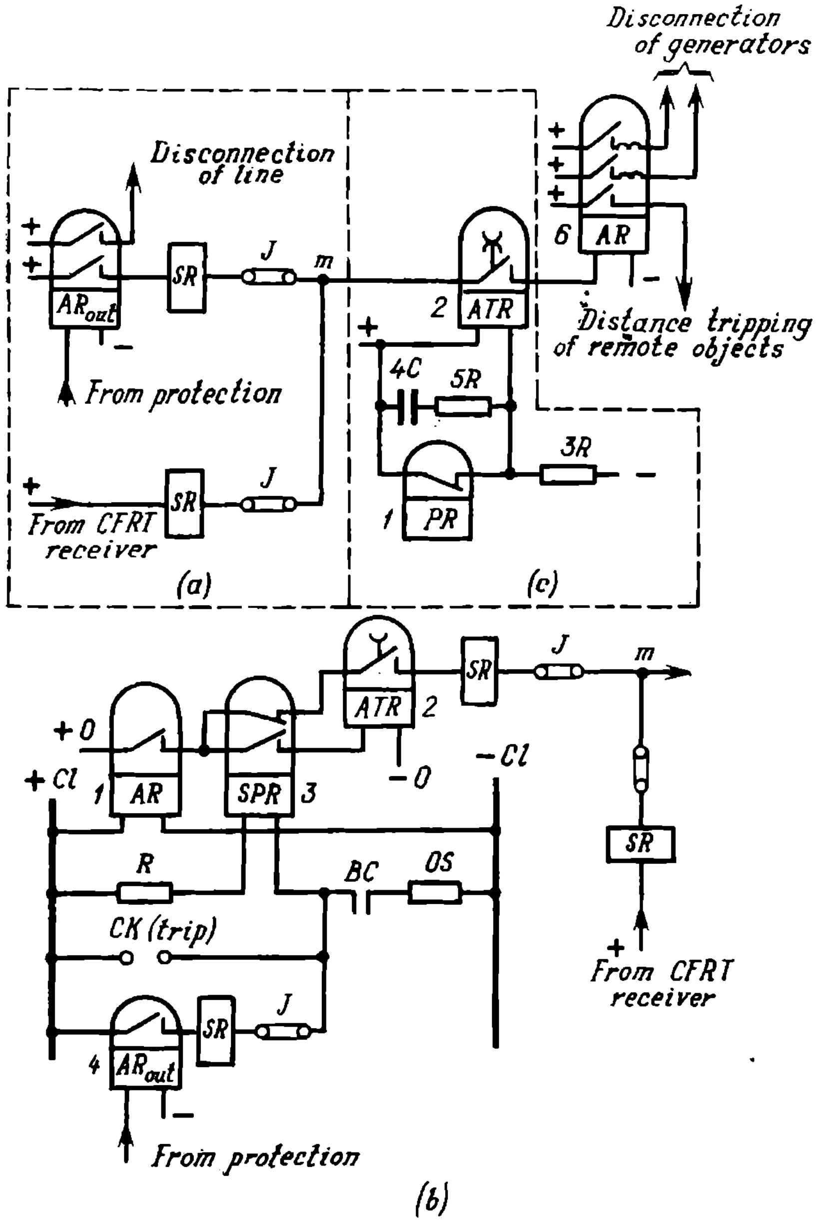


Fig. 4-13. Automatic unloading device

(*a*) and (*b*) variants of detecting elements; (*c*) storage of preceding operating conditions

the frequency band generated by the transmitter. If this band change occurs within a period less than 3 s, i.e., until the trouble blocking acts, this operation is not completed and the output circuits of the remote-trip device remain uninterrupted. Being tuned to the changed frequency, the receiver at the receiving end starts its operation and produces an output signal.

The *RT* equipment provides several control signals generated at frequencies at which the transmitter can operate under the control of the starting devices.

The c-f transmitters and receivers are connected to the transmission lines via coupling capacitors and connection filters similar to those used at the c-f protection stations. The ends of the transmission line should be provided with line traps. To improve interference suppression, the output transmitter and the input receiver are connected to the carrier channel through line filters. The generated frequency is quartz-controlled. The diagram of a remote-trip device developed by the All-Union Scientific Research Institute of Electric Power Engineering is shown in Fig. 4-14.

Relays *1AR* to *3AR* of the *RT* receiver are connected to narrow-band filters. Since the pilot frequency is circulating at all times, the relay *1AR* is excited. As this happens, the *1AR-1* and *1AR-3* contacts are opened, and the *1AR-2* contact is closed. The circuit of the blocking relay *BR* is closed (contacts *BR-1* and *BR-2* are closed, while contact *BR-3* is opened). When the transmitter operates pilot frequency f_1 disappears and frequency f_2 or frequency f_3 appears, depending on whether the starting relay *1SR* or *2SR* operates at the transmitting end. At frequency f_2 the relay *2AR* functions and makes the relay $1AR_{out}$ operate. The relay *3AR* functions and the relay $2AR_{out}$ closes at frequency f_3. The time taken by the contacts of the relays *2AR* and *3AR* to change over is insufficient for the *BR* relay to drop out and break the contact *BR-2*. The supply to the coil of relay *BR* is recovered through the circuit *2AR-3—1AR-3* or *3AR-3—1AR-3*.

Unloading the tie links by power station separation with subsequent two-branch operation. This method is clear from Fig. 4-15. Under normal operating conditions power station *A* supplies power to power systems *B* and *C*. The tie lines *A-B* are loaded close to their maximum capacity.

Any disturbance to the normal operating conditions (for example, spontaneous disconnection of the generating unit in power system *B*, disconnection of one of the parallel lines at some section of the *AB* tie line performed by switches *1* through *8*, and disconnection of one of the lines of the *AC* tie link by switch *10* through *13*) causes a tie line overload between power station *A* and power system *B*. The disturbance can be prevented by quickly unloading this tie line. The required unloading is accomplished by sectionalizing switch *9* with subsequent operation into two branches *AB* and *BC* and simultaneous disconnection of some of the generators connected to the busbar system of power station *A* from which the two parallel lines are run.

Opening the sectionalizing switch (*9*) also helps to prevent disturbances to the steady-state stabibity of transmission line *AC*, which may occur, for example, in the case of load throw-off in power system *B* or an open circuit in tie line *AB*.

The number of generators to be disconnected simultaneously with the separation of tie lines *AB* and *AC* depends upon the power carried by the tie lines under the pre-fault conditions and the load on each generator. The number is determined beforehand in the stability calculations of the power system and may be effected by a control computer (one of the first installations is in use at

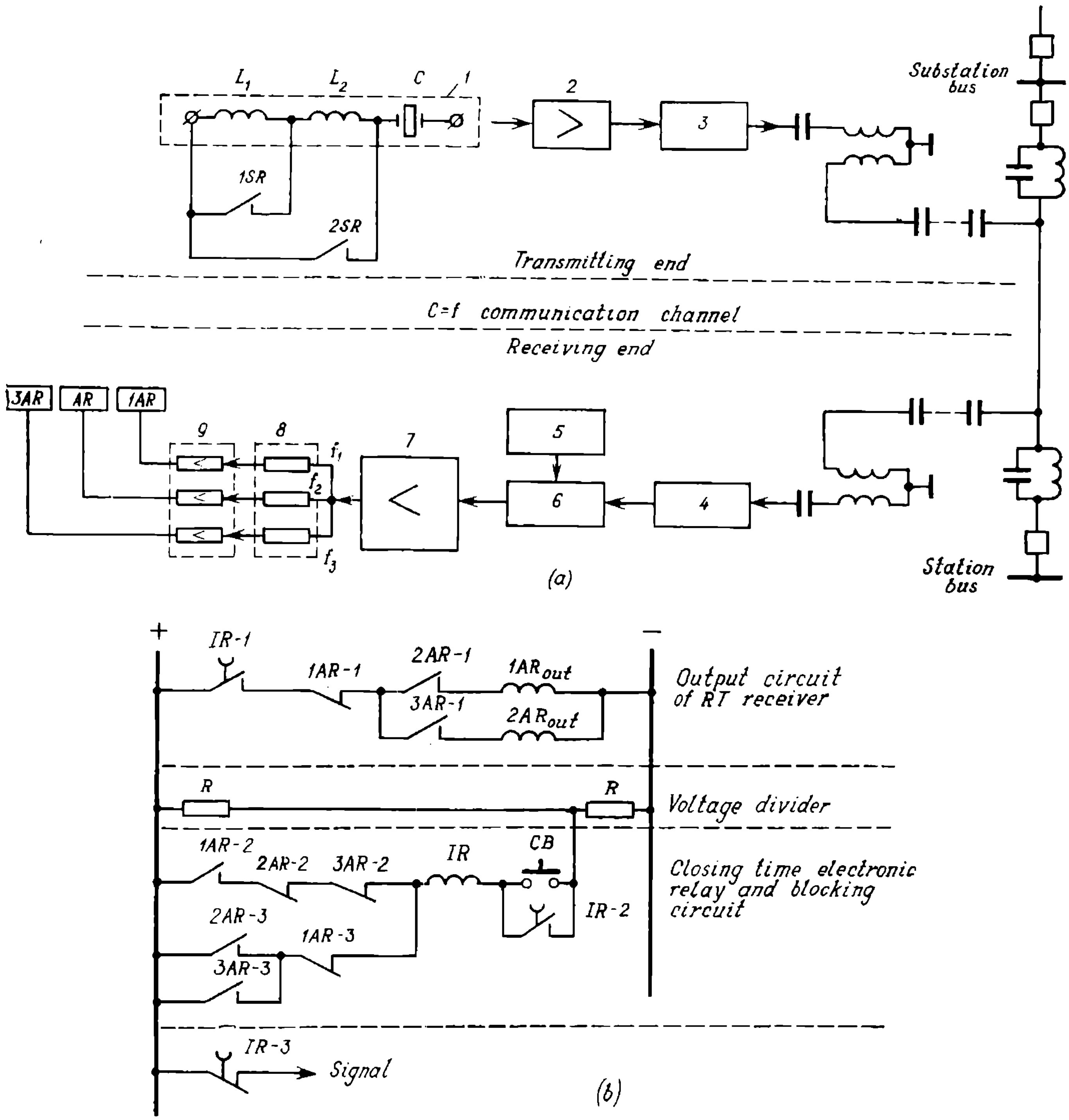


Fig. 4-14. Schematic diagram of remote-trip c-f device

(*a*) block diagram; *1* — c-f master oscillator; *2* — power amplifier; *3* — line filter; *4* — input filter; *5* — heterodyne; *6* — frequency converter; *7* — amplifier-limiter; *8* — narrow-band filters; *9* — amplifiers; *1AR* to *3AR* — auxiliary relays; (*b*) — connection of output circuits of c-f *RT* receiver

the Votkinsk hydroelectric station[4-11]), manually by an operator or automatically by the relaying system.

One automatic device is shown in Fig. 4-16. This includes two active power relays *R1* and *R2* with distinct operating settings (*R1* setting less than that of *R2*). When power flow exceeds the *R1* setting but is less than that of *R2* a few generators are disconnected. In the circuit shown in Fig. 4-15 only the sectionalizing switch is opened. When the power suddenly rises to the *R2* setting,

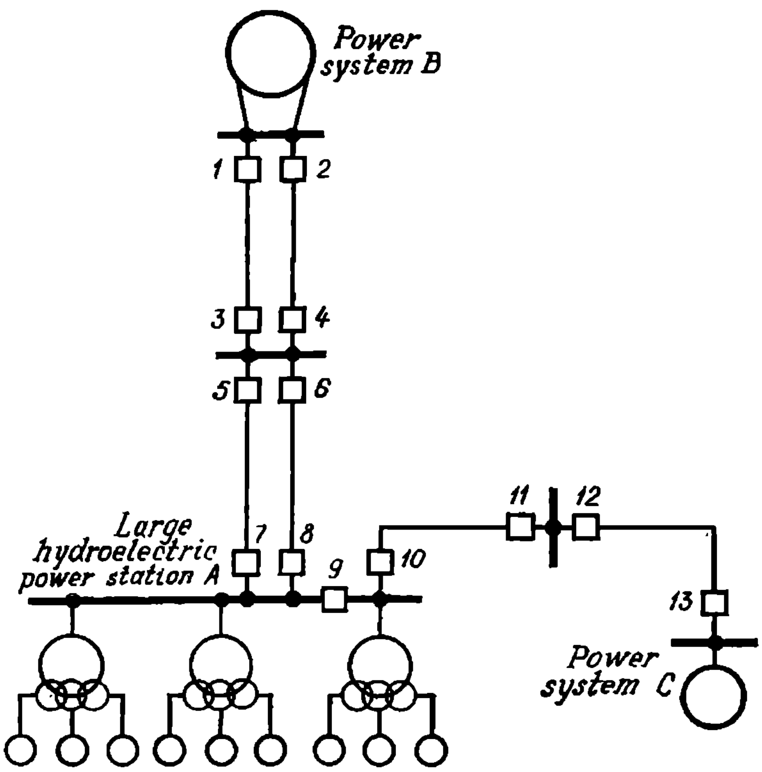


Fig. 4-15. Combined operation of power systems *B* and *C* through busbars of large-rating hydroelectric station *A*

relays *1* and *2* operate simultaneously and a greater number of machines are disconnected. For example, the sectionalizing switch and one or two more generators are isolated. If the power increases in excess of the *R1* setting, but less than that of *R2* and if, after operation of *R1*, the power flow fails to drop, the relay *R1* continues to keep its contacts closed or will reclose them very quickly in a time not exceeding the wiper-type contact setting time of the relay *5TR-3* (0.5 to 1.0 s) and the other group of generators becomes disconnected. The device is reset automatically, after the final contact operating time of the relay *5TR-2* has expired. This time is 4 to 5 s.

Other automatic devices are possible in which the number of disconnected generators is governed by the power value in pre-fault operation being controlled by individual active power relays with different operating settings.

Reducing real power lack in the receiving portion of the power system. When there are no power reserves in the receiving system the above-described techni-

ques for unloading the tie links by disconnecting part of the generating units at the supplying station may result in a reduced frequency. The tie links can also be unloaded by rapidly disconnecting part of the loads through a remote-trip device in the receiving system with subsequent automatic reconnection

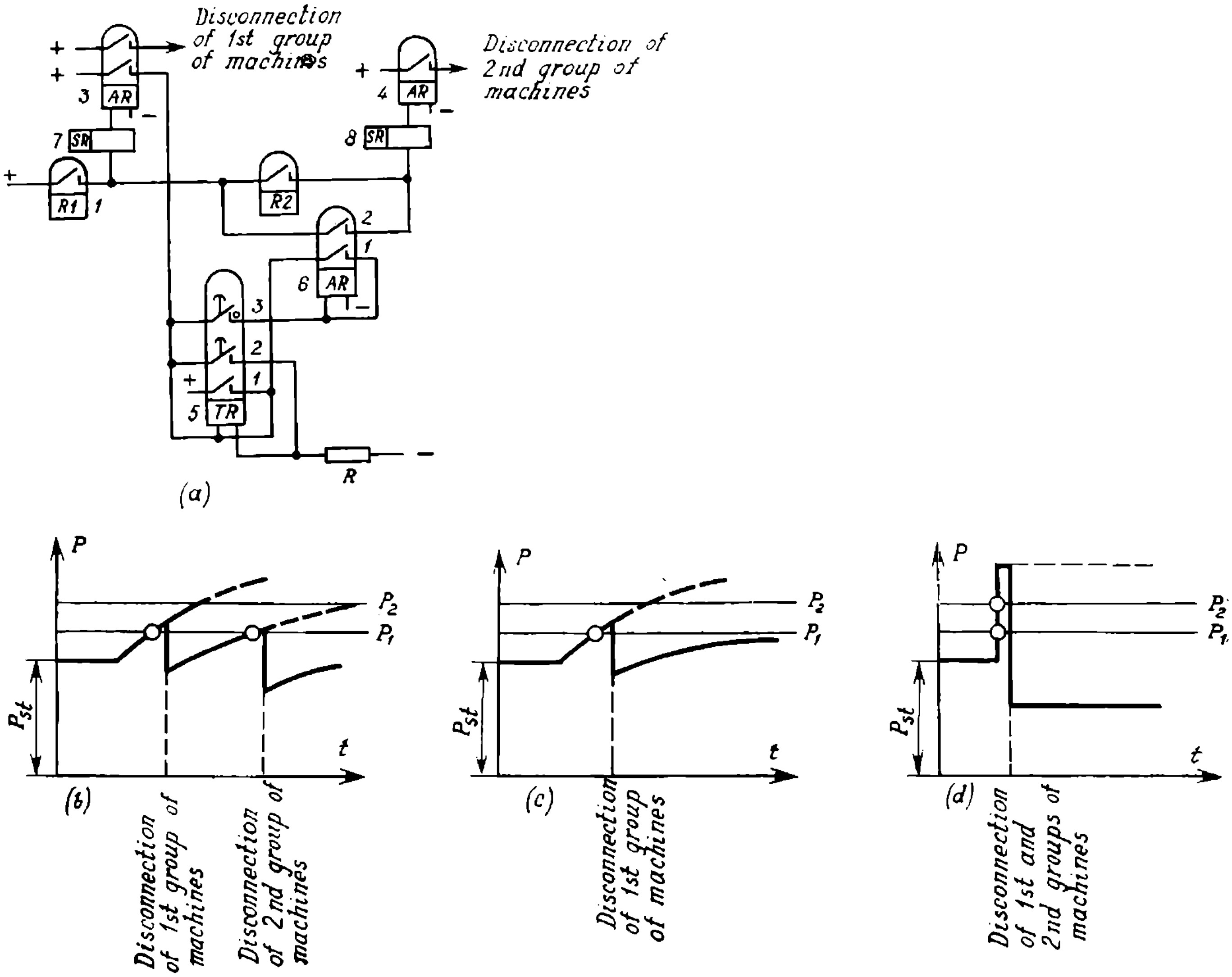


Fig. 4-16. Device for proportional unloading of power transmission system when power flow rises

(a) diagram; t_{5TR-3} is about 0.5 to 1 s (greater than the tripping time of the breaker of the first group of machines); t_{5TR-2} is about 4 to 5 s (greater than the time of maximum swing cycle); (b) change in power when the load on the transmission line rises smoothly (one case); (c) another case; (d) change in power at sudden increase of load

after clearing the cause of the tie link overload. This method is the better one, if the consumer permits short-time interruptions in power consumption (some metallurgical plants, for example) or the production is of less importance. Group isolation of the less important loads may be remotely accomplished if they are widely distributed.

In a number of cases the execution of the remote-trip command is dependent upon the voltage value at the consumer and is allowed if the voltage drops

below 90 per cent of its rated value. A voltage drop is another factor characterizing power loss and overload of the supplying tie links.

It should be noted that the steady-state stability can be effectively improved by automatic excitation regulation of generators and synchronous capacitors not only in the distributing part of the power system, but in the receiving one as well.

4-4. Automatic Controls for Improvement of Transient Stability

As mentioned previously, rapid isolation of short circuits is the principal way of improving transient (dynamic) stability. It is seen from equation (4-13) that the critical time of isolating a short circuit, without stability disturbance, depends on the critical angle δ_{cr} within which the emf vectors may depart under the transient conditions. The less the short circuit time, the less the departure angle is likely to reach the value of δ_{cr}.

As can be seen from Fig. 4-1, the afterfault value of P_{max} is of importance. This value is dependent on the magnitude of x_{12} under the same conditions[4-10].

Some automatic devices considered above as a means of improving steady-state stability can effectively improve transient stability if they are of quick response. These include devices which rapidly unload short-circuited tie links and when part of the parallel circuits are disconnected, and also devices that accomplish under the same conditions the forcing of capacitance banks of lengthwise compensation (where capacitance compensation is available).

Strong excitation regulation facilitates afterfault operation and thus improves transient stability (P_{max} increases during the afterfault operation). Important to transient stability are emergency braking devices used on overspeeding generators. The braking can be accomplished by other methods.

The first most simple method consists in the automatic isolation of some generators at the sending station or the switching over of part of the power system including the accelerated generators to a certain load. To this end the same rapidly responding devices, as those which prevent steady-state stability disturbances are used (see Section 4-3).

A more complicated method of decelerating generators is by short-time connection of resistances into the stator circuit of the generator or into the busbars of the tie line. The resistances are cut in once or repeatedly in case of a short circuit on the tie line, depending upon the drop in the active power or when the angle δ reaches its preassigned value. There is a proposal to cut in braking resistances when the electric power derivative reverses, which corresponds to the angle δ of 90 degrees. The electrical braking methods, however, are not widely applied although experimental installations have been tested. Perhaps, noninertia switches without movable parts (thyristor type, for instance) will allow this method to be used more effectively.

Mechanical braking of speeded-up generators is even more difficult although experiments have shown that such braking is feasible. However, due to its awkwardness this method is not applied.

In recent years, besides isolating generators, rapid (within fractions of a second) unloading of steam turbines is most widely used. This method ensures effective braking of the power units without their disconnection from the circuit. The entire unloading process with subsequent recovery of turbine output takes 3 to 5 seconds.

The effectiveness of various methods improving the transient stability will be now illustrated by an example of a short-circuit fault.

The instant a short-circuit occurs the electric power of the generator changes from curve *1* to curve *2* (Fig. 4-17). The turbine output remains the same as it

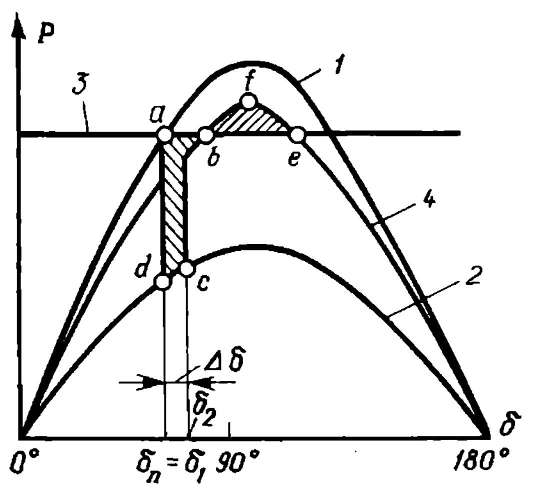


Fig. 4-17. Characteristic of power transmission process in emergency conditions

1 — electric power before fault; *2* — electric power during short circuit; *3* — output power developed by turbines; *4* — electric power after fault; S_{abcd}— accelerating area; S_{bfe}— decelerating area; $\Delta\delta$ — increment in angle δ for the short-circuit period

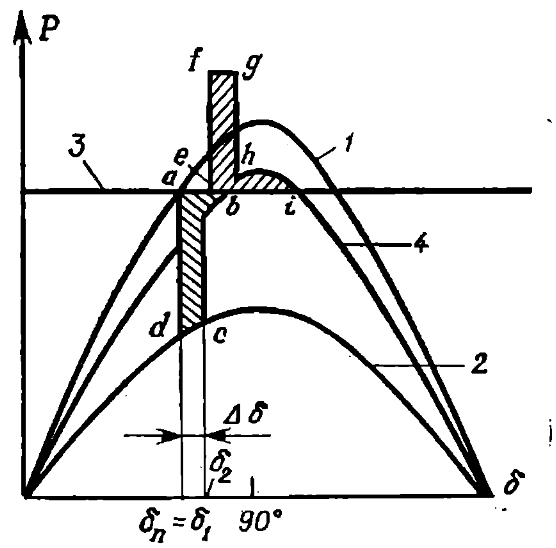


Fig. 4-18. Characteristic of power transmission process with electric deceleration of generator

1 — electric power before fault; *2* — electric power during short circuit; *3* — output power developed by turbines; *4* — electric power after fault; S_{aebcd}— accelerating area; S_{efghi}— decelerating area; $\Delta\delta$ — increment in angle δ prior to engaging decelerating device and clearing short circuit

was before the fault (straight line *3*). During the fault, while the short circuit is not cleared, the angle δ changes its value from $\delta_n = \delta_1$ to δ_2 due to an increase in generator speed. After isolating the short circuit, the power rises and its value is determined from curve *4*.

The excessive torque accelerating the generator is indicated by the area S_{abcd}. Stability will be maintained if this accelerating area does not exceed the decelerating area S_{bef} (in this case the generator output is greater than the output power of the turbine and the generating unit decelerates). In order to ensure the transient stability of the generator the accelerating area on one hand, may be reduced during the fault and, on the other hand, the decelerating area may be increased after clearing the fault.

It is seen from Fig. 4-17 that this aim can be attained both by the automatic excitation control devices, which increase the ordinates of curve *4* and, thus,

the decelerating area, and by the devices for rapidly isolating short circuits, which decrease the accelerating area. The emergency braking of the generators by cutting in a resistance for a short period increases the decelerating area due to an increase in the electric load without changing the turbine output. For this case, the torque characteristics are those shown in Fig. 4-18.

The method for securing the transient stability by disconnecting some of the generators is illustrated in Fig. 4-19. After the generators have been disconnected, the decelerating torque is indicated by the area S_{befg} which is far larger than the area S_{bfe} shown in Fig. 4-17.

When making calculations it must be kept in mind that disconnecting some of the generators increases reactance x_{12} somewhat with a resultant decrease in the ordinates of the power characteristic after correction of the fault.

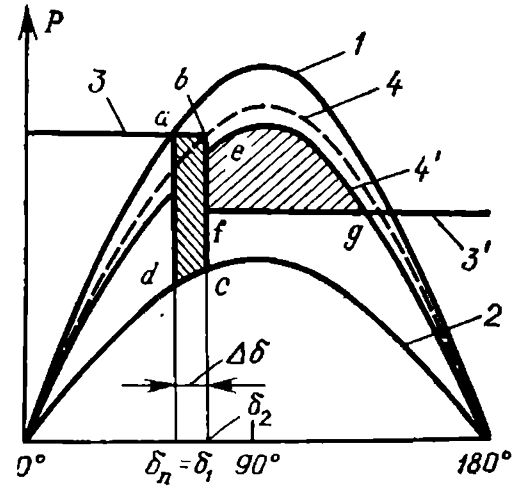


Fig. 4-19. Characteristic of power transmission process when some generators of power transmission station are disconnected

1 — electric power before fault; 2 — electric power during short circuit; 3 — output power of turbines before disconnection of some of generators; 3' — same, but when some of generators are disconnected; 4 — electric power after fault without disconnecting some of generators; 4' — same, but after disconnection of some of generators; S_{abcd}— accelerating area; S_{efbg}— decelerating area; $\Delta\delta$ — increment in angle δ prior to clearing short circuit and disconnecting some of generators

Rapidly unloading the steam turbines as a means of ensuring the transient stability of the generators became feasible after design of the electrohydraulic converters (EHC) which made it possible for forced pulses from external electrical devices to be fed to the hydraulic speed governors of the turbines.

The usual speed governor design employed under normal operating conditions is not suitable for rapid changes in turbine output during a transient process because of its slow action. Therefore, all Soviet-made turbines of capacities 300 MW and more are now furnished with EHC devices. The EHC devices for 200 MW turbines are available at option. The use of EHC with electrical inputs allows its use not only for stability, but also for a series of other problems (prevention of turbine racing, limitation of turbine output when the steam pressure is insufficient, etc.).

The amplitude and the duration of the pulse shaped by the external device for stability preservation and fed to the regulating system of the turbine via EHC must consider the gravity of the fault (type of short circuit and its duration), the prefault conditions (magnitudes and direction of power flows and the like), and the afterfault conditions. Hence, the "dosage" of turbine unloading must be determined by the combined analysis of a number of factors. The same applies to the automatic device used for disconnecting and electrically decelerating the generators. To solve this problem a special logic device is needed.

With the aim of simplifying the control process the so-called "program control" method may be used in which a precalculated control signal shaped by a relay device corresponds to certain type faults.

An external signal is formed by a device common for the whole station (Fig. 4-20). This signal acts through the electrohydraulic converter on the regulating system of the turbine. The control signal governing the amount and duration of unloading is accomplished in conformity with the extent of the external disturbance (for example, in compliance with the degree to which the forward-sequence voltage drops). The device is single-acting without further control of the process, thus open-loop regulation is effected.

The rapid unloading of the turbine ensures the transient (dynamic) stability of the generator due to an abrupt increase in the decelerating area (Fig. 4-21).

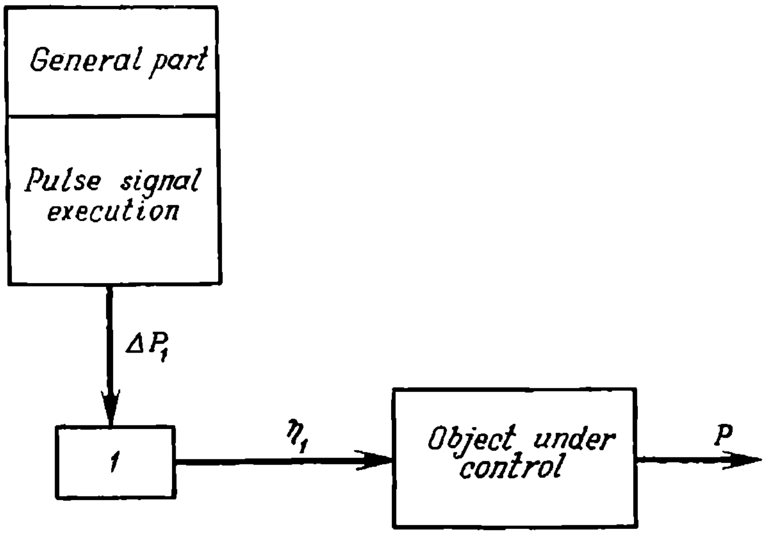


Fig. 4-20. Open-loop pulse control of steam turbine
1 — electrical attachment of electrohydraulic governor: η_1 — control action; ΔP_1 — magnitude of pulse signal; P — turbine power output

The relationship between the change in the turbine output and the value and duration of the rectangular pulse is determined by the pulse characteristics shown in Fig. 4-22. The dosage of the signal is made in irregularity units (ir). A signal of one irregulation regularity changes the turbine load by a value equal to its rated output. In order to make the servomotor which controls the governing valves of the turbine close at a maximum possible speed, a signal of 3 to 4 ir is fed through the electrohydraulic converter. It is seen from Fig. 4-22 that the delay in changing the turbine output after the unloading device has started its operation is 0.2 s. This is mainly due to the presence of free steam in the intermediate cavities of the steam path to the turbine blades.

Figure 4-23 illustrates a control signal shaping device made of auxiliary instantaneous pick-up relays with delayed armature drop-out. As dictated by the gravity of the fault, the sensing element feeds the "plus" of operational current to this or that auxiliary bus. Connected to these buses are the *1AR* relays which, after functioning, break the circuit of the *2AT* relays which determine the required duration of the rectangular pulse. The amplitude of the pulse is controlled by the resistor R_d. Provision is also made for aftereffect (slow removal) of the signal to prevent stability disturbances in the second and sub-

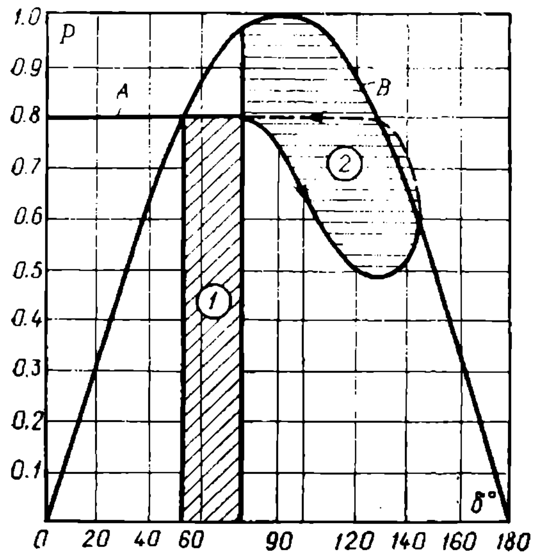


Fig. 4-21. Power characteristic in pulse braking of steam turbine

A — turbine power output; *B* — generator power output; *1* — accelerating area with three-phase short circuit; *2* — braking area with quick pulsed drop of steam admission to turbine. The arrow shows how power produced by turbine tends to recover after removal of pulsed limitation of steam inlet to turbine

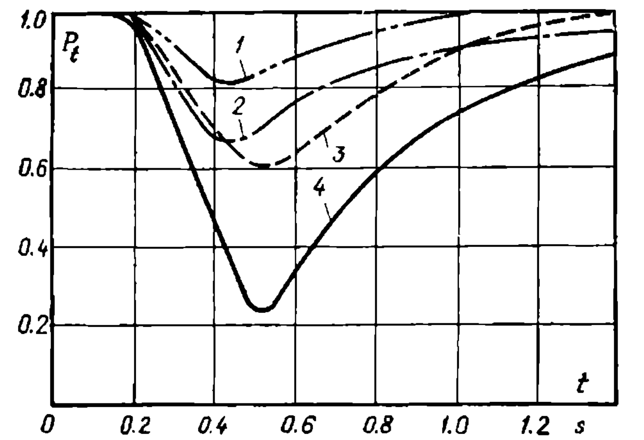


Fig. 4-22. Pulse characteristics of turbine K-200-130

1 — 2 ir, 0.12 s; *2* — 2 ir, 0.23 s; *3* — 4 ir, 0.13 s; *4* — 4 ir, 0.23 s

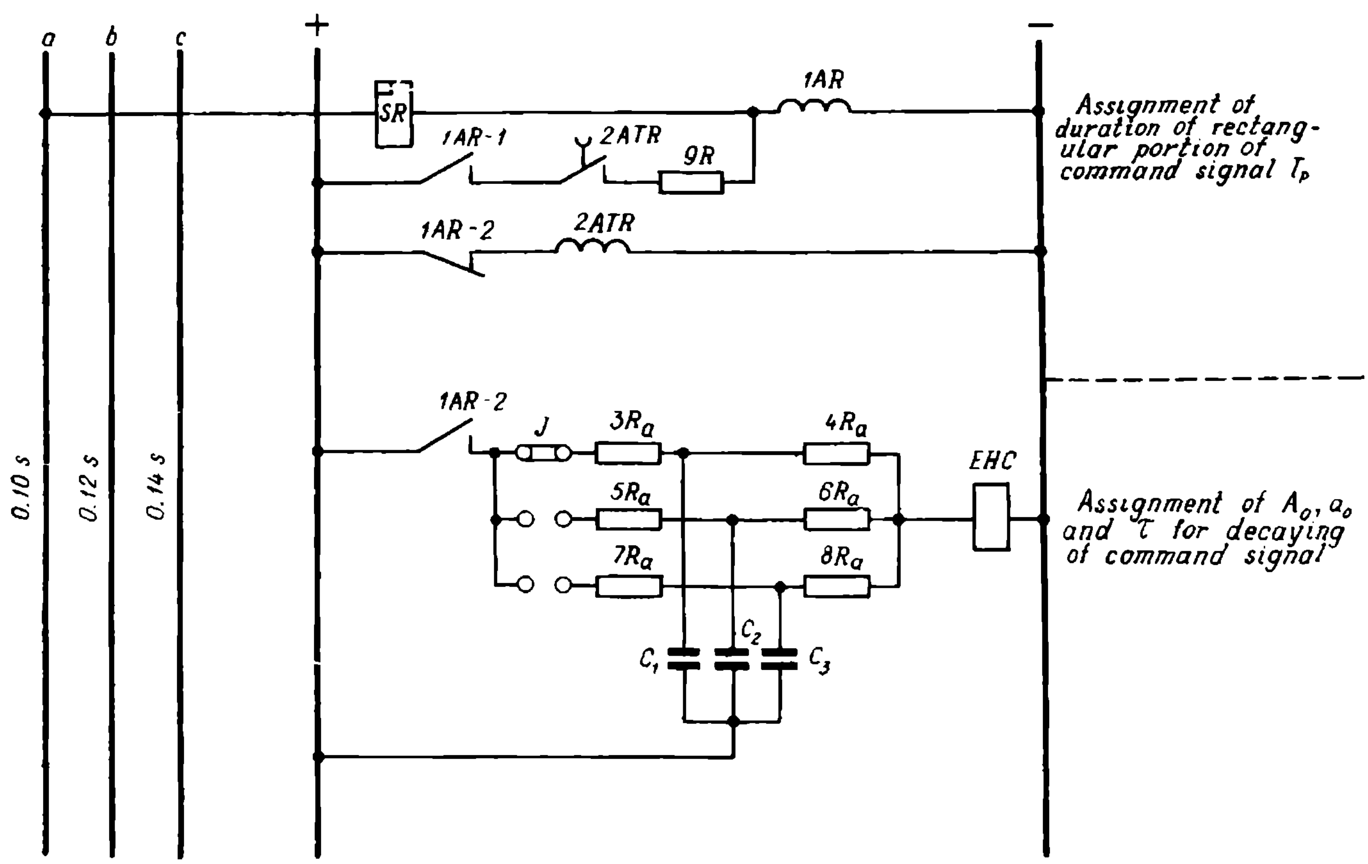


Fig. 4-23. Control pulse shaper. Operating current (+) is fed to busbars *a*, *b*, *c* by the elements that determine the time of forced braking of turbine

sequent cycles of swing because of a too rapid load pickup on the part of the turbine after its heavy short-time unloading.

The aftereffect of the signal is obtained by connecting the capacitors *C1* to *C3* which discharge exponentially (Fig. 4-24). The shape of the generated pulse signal is determined by the values A_0 and T_p which are the amplitude and the time of the rectangular portion of the signal; a_0 and τ determine the starting value of the trailing portion caused by the capacitance in the circuit and the time constant of damping.

If the transmitted power limit has changed but little in the afterfault conditions then, after short-time unloading, the output of the turbine may recover

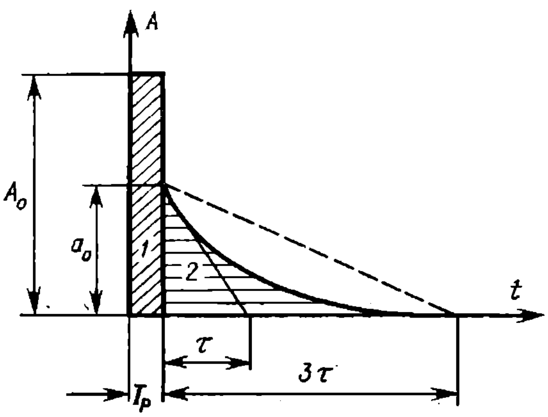


Fig. 4-24. Command pulse shape
1 — rectangular portion of pulse; *2* — trailing portion due to capacitor discharge

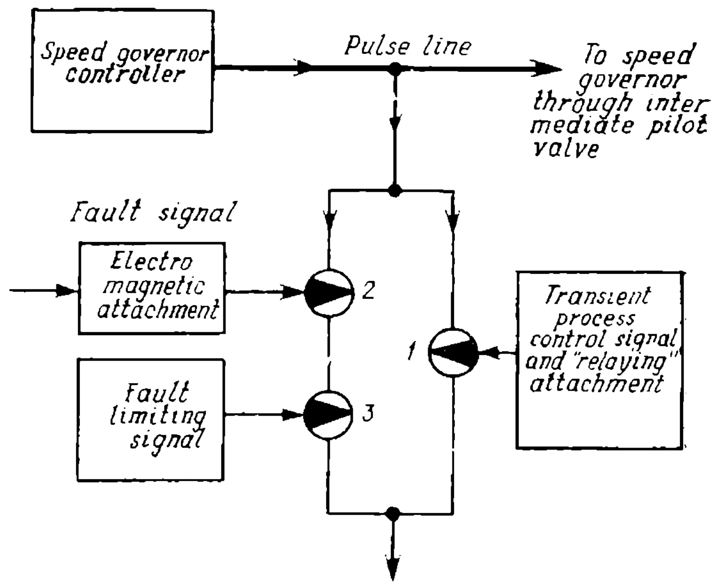


Fig. 4-25. Block diagram of electrohydraulic attachment

to its prefault value. If the power limit has dropped (due to the disconnection of one of two parallel transmission lines) and the prefault power cannot be transferred over the tie line in operation then, after an emergency unloading of the turbine, its output power cannot be raised to the prefault value and must be limited. This function is performed by an automatic turbine power limiter (APL).

The APL detecting element must determine the amount of required unloading, taking into account that the power station as a whole can be unloaded by a control action on several of the units operating in parallel.

To ensure transient stability the APL operation is usually preceded by a short-time turbine unloading. This system, however, may be built as an individual device which can change the turbine output according to the afterfault steady-state stability limit.

A speed control mechanism is generally used as the actuating element of the APL device. The AOM-67 automatic power limiters developed by the All-

Union Heat Engineering Institute act upon the speed governor control system by varying the flow rate of the operating fluid in the pulse line (piping) connecting the controller of the speed governor to the governor intermediate pilot valve (Fig. 4-25)[4-6].

The signal to control the transient process is shaped by a relay attachment to the electrohydraulic converter. This attachment generates a rectangular pulse of specified duration and a residual signal decaying with time. The regulation is effected through valve *1* which opens the return outlet for the driving fluid of the pulse line in order to abruptly reduce the turbine output. The pick-up time of the relay attachment is 0.06 s.

The turbine output and the power generated afterfault are equalized by regulating the working fluid drain from the pulse line in the second parallel branch of the draining device. This branch has two regulating valves *2* and *3*. Valve *2* opens upon receipt of an emergency signal. The drain is regulated by valve *3* which is controlled by an electromechanical follow-up system.

The control signal is formed by comparing the power generated after the fault with the turbine output power before the fault. The signal acts on valve *3* until the turbine output corresponds to the afterfault power which is sensed by an electrical power indicator. The beforefault power is clamped by the control valve.

Figure 4-26 shows the block diagram of the electrical attachment to the K-300-240 ЛМЗ turbine [4-7]. As it has been stated above, the "electrical input" of the regulating system is used for a number of purposes, emergency decelerating among them. The units comprising the electrical attachment assembly are contained within the dashed outline.

The letters *HPP*, *IPP*, *LPP* denote the high, intermediate and low pressure parts; *B*, boiler; π_1, π_2, and π_3, steam pressure values in the steam filled spaces; *TP*, turbine-driven feed pump; ξ_1 and ξ_2, *HPP* and *IPP* regulating respectively valves; V_1 and V_2, valves of the reduction-cooling units; *SM*, servomotors of valves ξ_1 and ξ_2; *TG* turbogenerator, type TBB-300-2; *AG*, auxiliary generator; *VI*, vacuum indicator; *MSPI*, main steam pressure indicator; *GPV*, speed governor pilot valve; *SGVSI*, speed governor valve stroke indicator; *SPI*, intermediate superheater steam pressure indicator; *HB*, hydraulic booster; *EMC*, electromechanical converter; *SMA*, summing magnetic amplifier; *FC*, functional converter; *PI*, power indicator; *FU*, frequency unit; and *DIF*, differentiator connected either to the input of the stroke indicator of the speed governor or to the output of the frequency unit.

The following signals are fed to the electrical attachment:

(a) Current and voltage of the turbogenerator from the instrument transformers to the sensing unit of the power indicator.

(b) Signals from power indicator *PI* and pressure indicator *SPI* of the intermediate superheater to the input of the device for shaping the signal of initial irregularity correction. The latter device forms a signal proportional to the initial irregularity correction (IIC)

$$K_{iic}=\frac{\nu_2}{\delta_N}-\frac{\pi_2}{\delta_P}$$

where ν_2 = relative value of generated power
π_2 = relative value of the steam pressure in the intermediate superheater
$1/\delta_N$ $1/\delta_P$ = steam power and pressure regulation factors, respectively

(c) Voltage (frequency) of the carrier-frequency subexciter *AG* of the generator excitation system or the signal from the speed governor valve stroke indicator *SGVSI* to the input of the *DIF* differentiator (acceleration transmitter).

(d) Signal from the main steam pressure indicator *MSPI* and vacuum indicator *VI* in the turbine condenser to the input of the protection device.

Provision is made for additional input signals from the external automatic devices which rapidly unload the turbine.

There are several unloading stages depending upon the gravity of the emergency. They differ in amplitude and duration of the pulse fed to the electrical attachment. The first

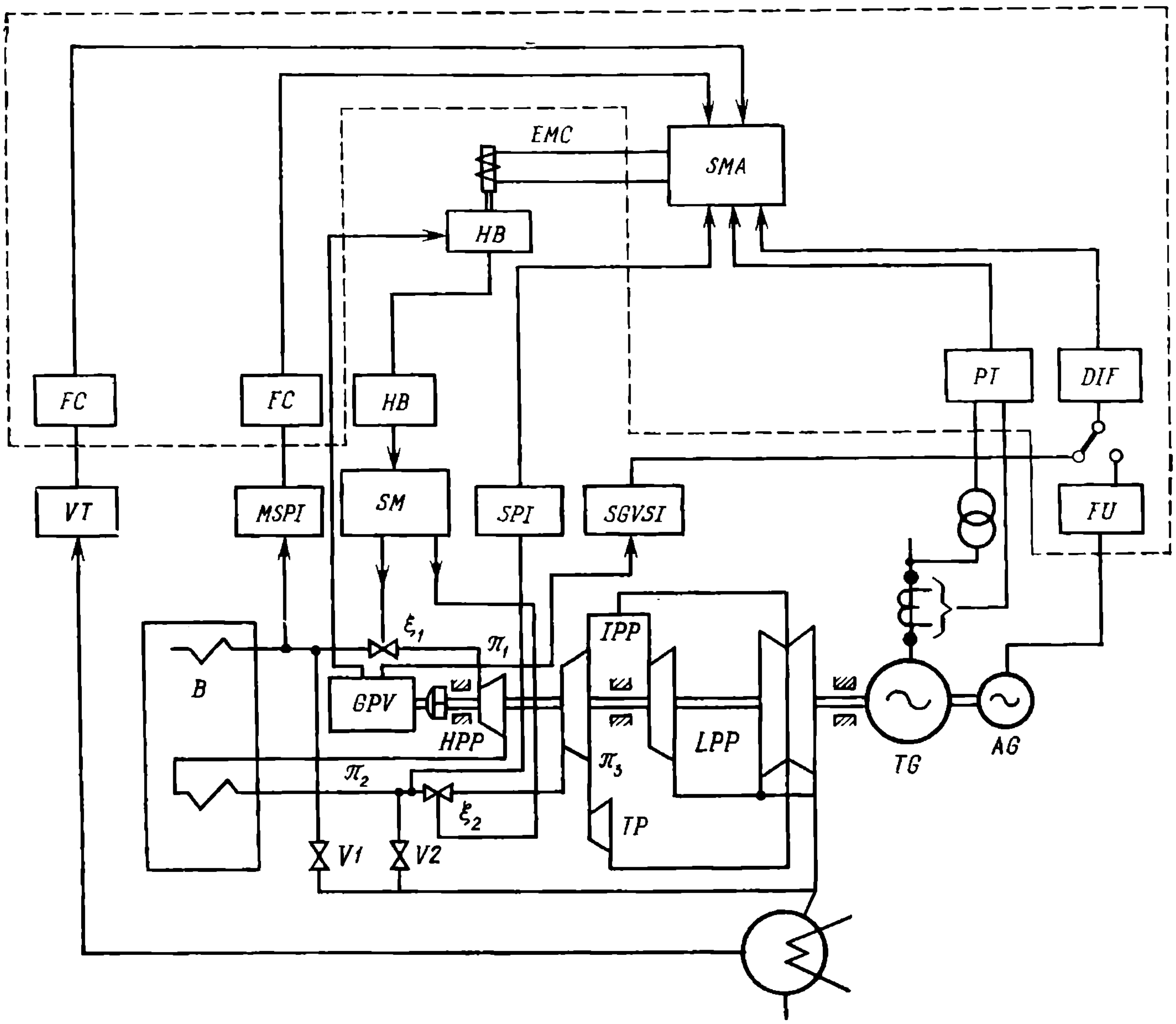


Fig. 4-26. Block diagram of automatic control system of turbine K-300-240 (electrical attachment units are contained within the dashed outline)

stage can be accomplished by rectangular pulses exponentially decaying in time. The second and third stages may have a rectangular leading edge and be cancelled after a specified period, etc.

The pulses of each stage are shaped by their own output devices (auxiliary relays, time relays, and capacitors for exponentially canceling the signal etc.). With simultaneous operation of several stages, the priority rests with the heavier stage, i.e., the stage that unloads the turbine the most. The unloading automatic devices cancel the effect of the differentiator.

To protect the turbine against overspeeding the action of the electrical attachment, is fully used when the generator switch is disconnected (from the interlocking contacts or from the positioning relay) and also when the frequency rises to 52-52.5 Hz. In the latter

case the differentiator continues its action on the electrical attachment. As its name implies the differentiator responds to turbine speed changes. It is bad practice to keep the differentiator permanently in the circuit as it may cause unwarranted unloading of the turbogenerator under swing conditions and in the case of the generator output fluctuations.

4-5. Automatic Devices for Sectionalizing Power Systems to Prevent or Eliminate Asynchronous Operation

Different types of automatic sectionalizing devices are used to suit the specific operating conditions and configurations of power systems. When stability disturbances cause no resynchronization (for example, when disconnecting large-rated transmission and when operating the power system components through a small capacity tie line) sectionalizing automatic devices

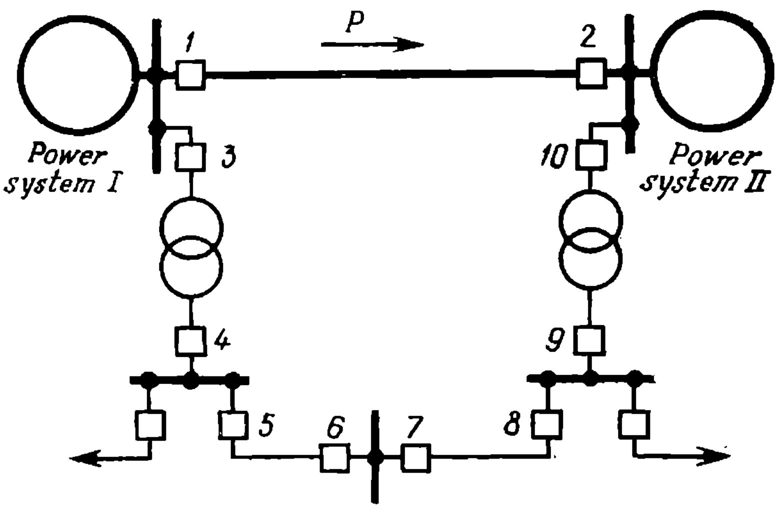


Fig. 4-27. Parallel operation of power systems over two tie links

providing the most rapid response are applied. If there is a need to check a resynchronization possibility, it is better to utilize sectionalizing devices which operate if asynchronous operation continues longer than a permitted period.

Let us consider the operating principles underlying various types of sectionalizing devices.

(a) **Automatic sectionalizing devices of instantaneous action.** Described below are several versions of such devices.

1. The most simple variant is the use of current relays with series-connected contacts in the A, B and C phases. The low probability of three-phase short circuits during which these devices may misoperate makes this variant sufficiently reliable, especially if the device is used in a small-power link by-passing an often heavily loaded link large in rating (Fig. 4-27).

However, the above variant performs an unwanted sectionalizing operation even with a successful automatic reclosure of the powerful tie line.

Instantaneous sectionalizing makes even short-time asynchronous operation impossible and prevents the occurrence of heavy voltage drops near the electric centre. This can happen when the automatic sectionalizing device performs sectionalization after several asynchronous cycles rather than instantaneously. The instantaneous response devices allow full employment of the transmission capacity of the "low-power" tie line and discriminating against successful operation of the ARC device on the "powerful" tie line.

Prevention of heavy voltage drops is a decisive factor when many important consumers are sited close to the electric centre as voltage drops affect their production process.

Improving the response of the above instantaneous sectionalizing automatic devices to three-phase short circuits may match them with the operation of

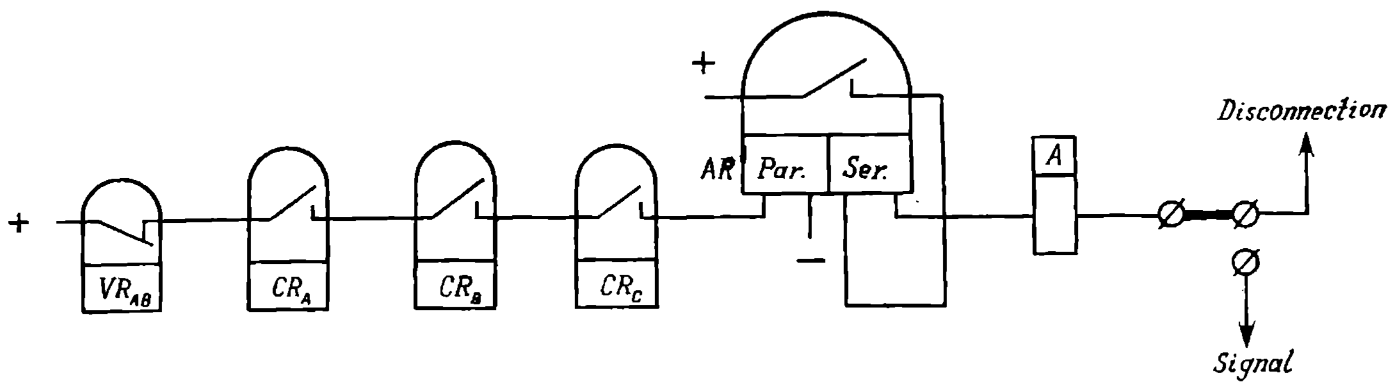


Fig. 4-28. Device for quick tripping in asynchronous operation

the ARC device which isolates the automatic sectionalizing devices and recloses the switch when there is no voltage from the disconnected line side. If the switch has an ARC device which does not provide this operation process (like an ARC device without synchronism-checking equipment) the ARC device must not operate while the automatic sectionalizing device functions. Otherwise, multi-shot repeated asynchronous reclosures may occur.

Increased response to three-phase short-circuits on sections adjacent to the tie line is also obtained by using a time delay of 0.25 to 0.3 s in order to discriminate against the operation of the rapid-response protection devices. This measure should be substantiated for each case by considering the time the current relay contacts remain closed when the stability is disturbed.

With the above automatic sectionalizing device, the pick-up current of the current relays must be 1.3 to 1.5 times greater than the maximum load current and at least 1.5 to 2 times less than the maximum equalizing current, when the parallel power systems are at their minimum. The possibility of using the current starting element of automatic control must be checked from these conditions.

To improve the automatic control response and obtain better isolation against load currents the circuit should be supplied with an undervoltage relay (Fig. 4-28). If the setting of a relay connected to the voltage U_{BC} is less than 40 per cent

of the rating, one current relay connected into phase A may be used. Such a device will function very rarely and only when a three-phase short circuit occurs near the location of the protective device.

In many cases the undervoltage relay with a low pick-up setting imparts automatic selectivity to the device. The sectionalizing devices may function on sections close to the electric centre which often is the midpoint separating the powers (the zero flow point). A heavy voltage drop occurs at the electric centre when the emf vectors are apart more than 120 degrees.

2. Using a real (active) power relay gives another variant for instantaneous automatic sectionalizing purposes. The relay may be a three-phase forward sequence device, or include three single-phase relays with series-connected contacts having a pick-up setting $P_{\text{pick-up}} = 0.8\ P_{\max}$ (see Fig. 4-7). This automatic device functions when the angle δ is about 60 degrees. For better isolation of the automatic control against synchronous swings and overloads (when no asynchronous operation arises) its operation is usually permitted only after disconnection of the high-power link and if the power it transmitted before the fault would cause stability disturbances when shifted to the low-power link. Disadvantage of this variant is the use of complicated relays and the fact that their operation depends on the value of voltage at the installation point. As to the magnitude of the transmitted power, the critical values of the settings should be oriented towards the minimum value of the service voltage.

3. The third variant of the instantaneous sectionalizing devices uses an impedance relay (resistance—reactance, or directional) as a detecting element. As compared to the current, voltage and active power relays, the impedance relay makes better use of the overloading properties of the tie links, since its operation more clearly clamps the critical value of δ_{cr} at which the power carried by the tie link must be separated. More than that, it "self-adjusts" to the before-fault value of the voltage.

One simple automatic sectionalizing device employing impedance relays is shown in Fig. 4-8. The circuit is similar to that of the automatic sectionalizing device considered earlier. The use of current relays prevents misoperation of the device due to a fault in the voltage circuits and when asymmetric external short circuits occur.

When using a short-circuit current protection system, the sectionalizing device can be easily made from an impedance relay (resistance and reactance, or directional) employed as a starting element with properly chosen pick-up settings. The best operating results are obtained when the device is installed at the substation, near the electric centre.

4. The above described types of automatic sectionalizing devices function when short circuits occur. As mentioned previously, special measures must be taken to exclude unwanted operation and clear the after-effects of such operation, if any. To completely prevent the operation of instantaneous sectionalizing devices during short circuits (three-phase ones included) a circuit may be made using protection interlocking principles when swings occur.

Well known principles may be applied, the only difference being that in the case of swing the protection interlock causes the protection system to ope-

rate during short circuits but prevents its operation during synchronous swings and asynchronous operation which are not accompanied by short circuits. The sectionalizing devices, however, must automatically operate when asynchronous working takes place and isolate themselves during short circuits.

Figure 4-29 illustrates an automatic sectionalizing device whose operation is permitted when the electrical variables undergo smooth changes according to the stability disturbances and forbidden when these variables suddenly change indicating a short-circuit fault.

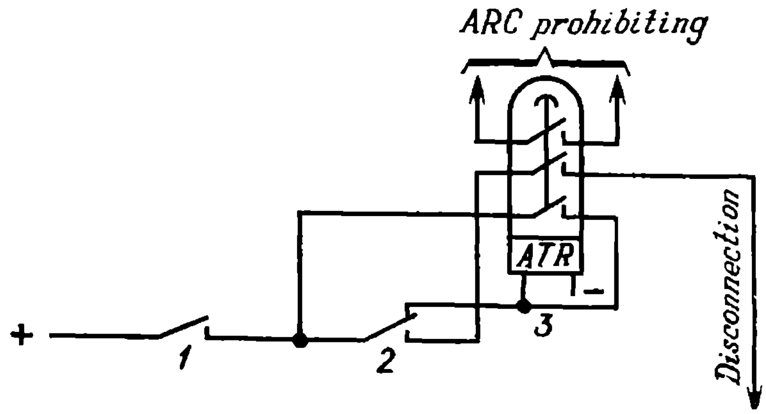


Fig. 4-29. Instantaneous sectionalizing device
1 — more sensitive relay; 2 — less sensitive relay; 3 — auxiliary relay

Shown in Fig. 4-30 is a diagram of an automatic sectionalizing device which cannot operate during short circuits. This is effected by a device which breaks its circuit when electrical magnitudes of backward or zero sequence appear even for an instant. Components of these sequences, appearing in the circuit, indicate a short circuit which needs no sectionalization.

(b) **Sectionalizing devices with asynchronous operation control.** In order to distinctly distinguish between synchronous swings in a power system and asynchronous operation, S.A. Lebedev designed a detecting element in the form of a relay responding to the angular values between the emf vectors of machines operating in parallel. Any type of relay having the following torque can be used

$$M = U_1 U_2 \cos(\varphi + \alpha) \tag{4-26}$$

where U_1 and U_2 = voltages applied to the coils of the relays
φ = angle between the vectors of U_1 and U_2
α = internal angle of the relay

If voltage from points M and N of the power system (Fig. 4-31) (from the points to which the emf's E_1 and E_2 are applied) is fed to the relay coils, then with the internal angle $\alpha = 90$ degrees, the relay torque will be null when the angle $\delta = \varphi = 0$ and 180 degrees, whereas with the internal angle $\alpha = 0°$ the relay torque will be null when $\delta = \varphi = 90$ and 270 degrees. Thus, if use is

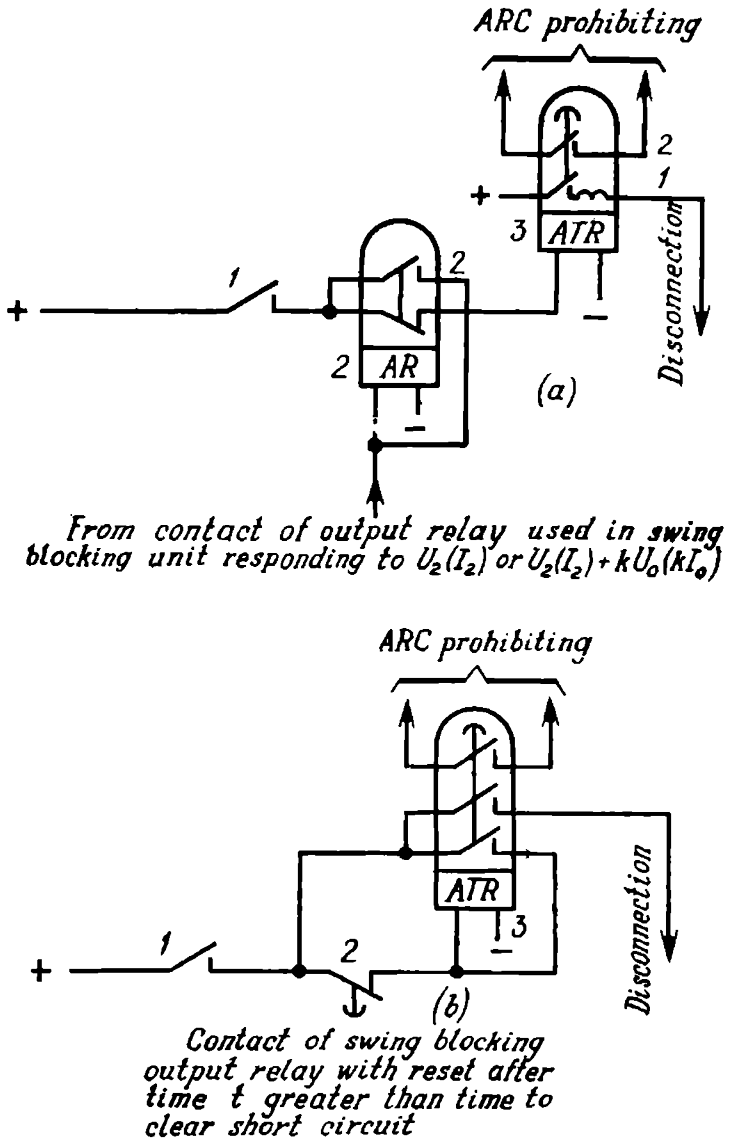


Fig. 4-30. Instantaneous sectionalizing device

(a) contact of output relay to block against I_2 swing; (U_2) — potential to close circuit of relay *2AR*; (b) contact of output relay *2* to block against I_2 swing, (U_2) with reset after specified time. The contact performs breaking function; *1* — contact of starting element of device; *3* — auxiliary relay

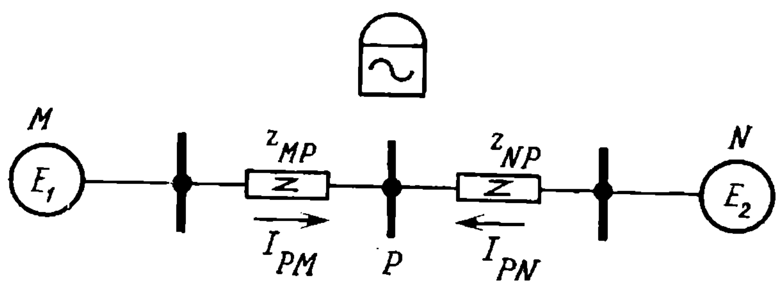


Fig. 4-31. Power system

made of two relays having different internal angles, a certain sequence of contact closing will correspond to a certain change of the angle δ in time.

The voltage at point P

$$\left.\begin{aligned}\dot{U}_P &= \dot{E}_1 - \dot{I}_{PM} z_{MP} \\ \text{and} \qquad \dot{U}_P &= \dot{E}_2 - \dot{I}_{PN} z_{NP}\end{aligned}\right\} \tag{4-27}$$

Hence, if the voltage from the substation P is impressed upon the relay so that

$$\left.\begin{aligned}\dot{U}_1 &= \dot{U}_P + \dot{I}_{PM} z_{MP} \\ \text{and} \qquad \dot{U}_2 &= \dot{U}_P + \dot{I}_{PN} z_{NP}\end{aligned}\right\} \tag{4-28}$$

the above voltages will correspond to the values of $\dot{E}_1$ and $\dot{E}_2$. The voltage drop across the impedances z_{MP} and z_{NP} is compensated by a current proportional to

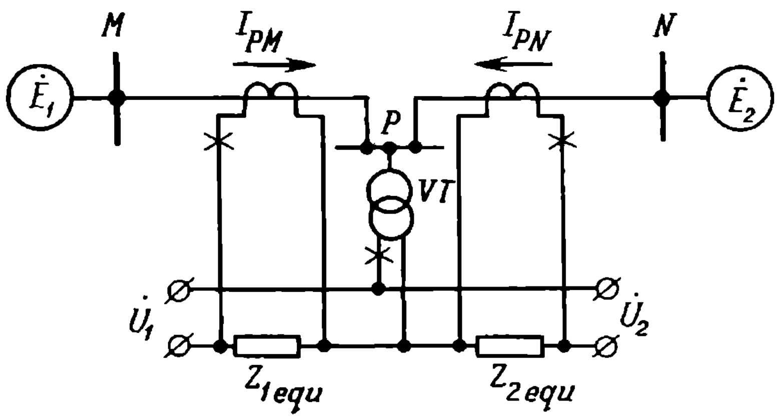


Fig. 4-32. Operation of device detecting asynchronous operation

the line current flowing in the impedances $z_{1\ equ} = k_1 z_{MP}$ and $z_{2\ equ} = k_2 z_{NP}$. The voltage drop across the impedances $z_{1\ equ}$ and $z_{2\ equ}$ is added to the voltage fed to the relay coils from the voltage transformer VT (Fig. 4-32). Such circuits are known as phantom circuits.

If the coefficients k_1 and k_2 are equal to unity the voltage drop is fully compensated up to points M and N. If k_1 (k_2) is greater than unity overcompensation occurs beyond point M (N), and if k_1 (k_2) is less than unity, undercompensation takes place.

The device for detecting asynchronous operation must be discriminated against the effects of a short-circuit. In this instance, the output pulse is formed after a certain alternation of vectors $\dot{E}_1$ and $\dot{E}_2$ when the emf angle passes the zone of 0-90-180-270 degrees, i.e., when synchronism is lost. If the device is installed at a power station, one of the voltages may be applied to it from the

terminals of an auxiliary synchronous machine mounted on the generator rotor shaft.

The above device operates only at a certain amount of slip. For this, the output circuit must include a time relay and an operation pulse counter. The time relay allows the formation of an output signal at a certain duration of the output signal generated by the counter.

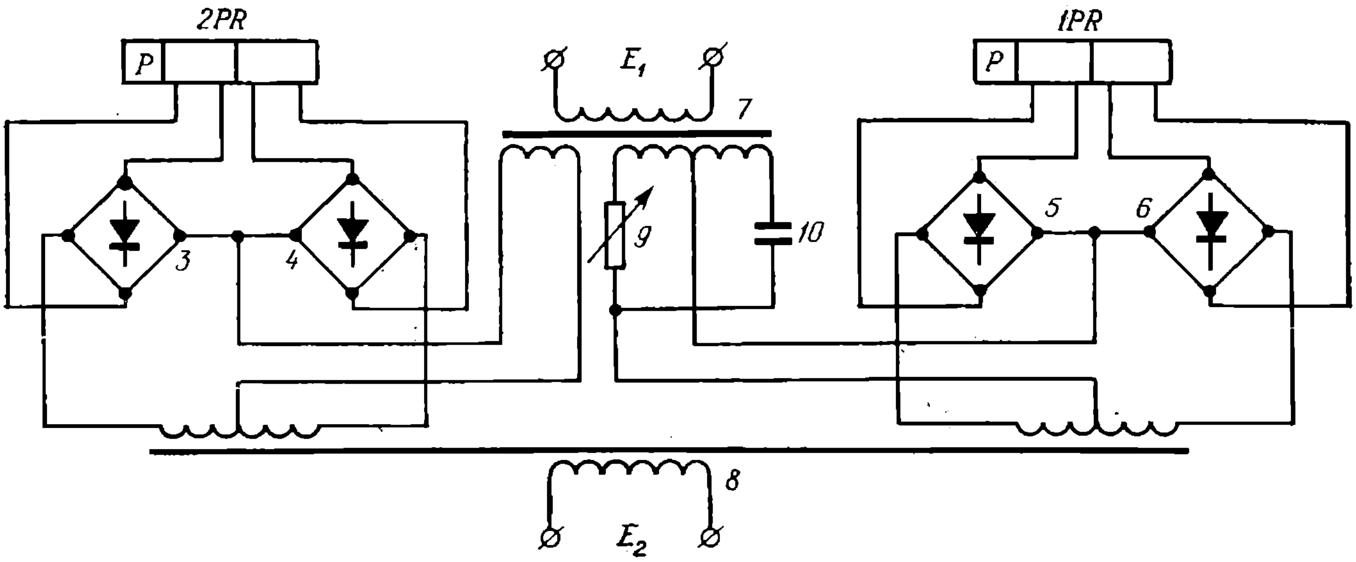


Fig. 4-33. Connection of relay in device detecting asynchronous operation

1, 2 — polarized relays; *3-6* — rectifiers; *7, 8* — intervening transformers; *9* — resistor; *10* — capacitor to adjust internal shift angle of relay *1PR*

The design of a device responding to variations in the angle δ is shown in Fig. 4-33. The connection diagram and a vector diagram are given in Fig. 4-34. This device employs two directional two-way relays having internal angles shifted with respect to each other through 90 degrees. One relay is of the cosine and the other of the sine type. Used as the directional units are instantaneous polarized relays connected through rectifiers.

Under normal operating conditions (Fig. 4-34) the vector $\dot{E}_1$ leads the vector $\dot{E}_2$ by the angle δ (it is assumed that the generators deliver power to the power system). In such a mode of operation, contacts *2* of the relays *1PR* and *2PR* (Fig. 4-34*a*) are closed. The areas within which the angle δ varies, while contacts *1* and *2* of the relays *1PR* and *2PR* remain closed, are shaded. Since the contact *1AR-1* is closed, current flows in the coil of the instantaneous auxiliary relay *2AR*. The relay *2AR* opens contact *2AR-2* and closes contacts *2AR-1* and *2AR-3*. The contact *2AR-3* prepares the output circuit of the device and the contact *2AR-1*, the circuit holding the relay *2AR* (after the relay *2PR* has closed the contact *2PR-1* and the relay *1PR* has opened the contact *1PR-2*).

When $\delta = 180$ degrees, contact *1* of the relay *2PR* closes and contact *2* of relay *1PR* opens. As indicated above, the relay *2AR* still remains closed. After the angle δ has passed the 180 degree position and lies within 180-270 degrees contact *1* of the relay *1PR* closes to send an output signal. As the angle δ

increases further contact *1* of the relay *2PR* opens and deenergizes the coil of the relay *2AR*. Thus, the circuit is prepared for new (repeated) operation after the angle δ has passed through 360 degrees. If swings do not make the angle δ exceed 180 degrees, i.e., the synchronism is not lost, the output circuit is not closed. The circuit also does not close when vector $\dot{E}_1$ lags vector $\dot{E}_2$.

The device can operate properly also when the voltage applied to the relays *1PR* and *2PR* is not exactly compensated by for the voltage drop to the points to

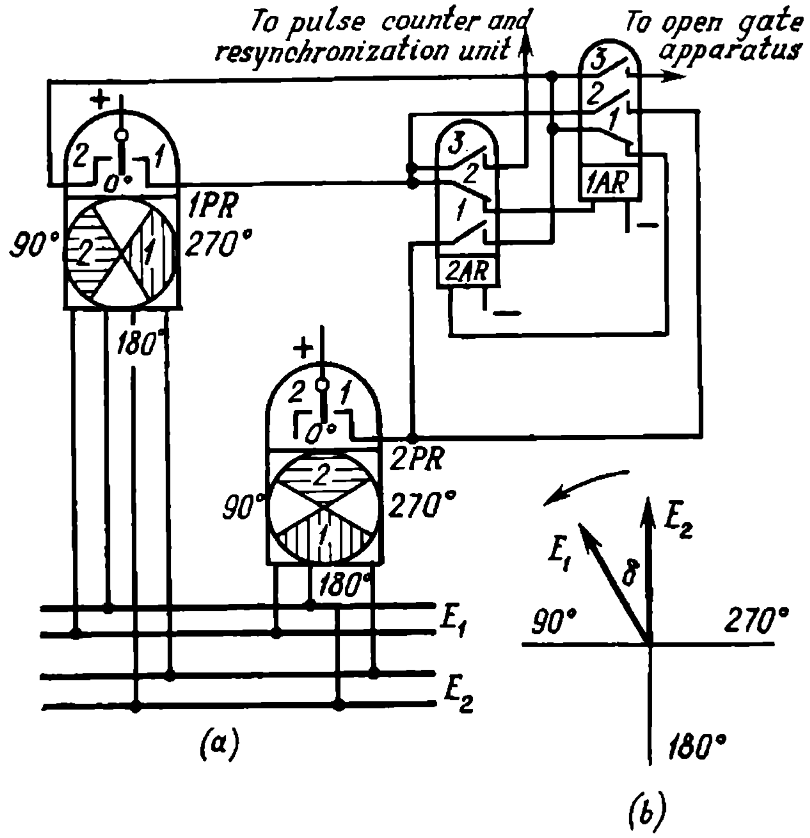


Fig. 4-34. Device for detecting asynchronous operation
(*a*) relay connection diagram; (*b*) explanatory diagram

which the emf is applied. Since the output circuit is closed only after the compensated voltage vectors have turned through 180 degrees relative to each other, it is sufficient under different operating conditions to ensure dependable compensation for the voltage drop across the section from the location of the device beyond the electric centre towards the points to which the emf is applied. On both sides of the electric centre the voltage vectors turn with respect to each other through 180 degrees during asynchronous run, a fact which does not occur during synchronous swings.

Disadvantage of this device is that it is very complicated and provision must be made to prevent the effect of the output signal in case of short circuits (by the above-mentioned interlocking units or the use of an operating pulse counter, the latter rules out instantaneous breaking of the tie link).

In many instances a simpler device incorporating an instantaneous current relay and active power relay may be used as a synchronism loss detector. Synchronism disturbance and an angle δ in excess of 180 degrees are characterized by the change of the active power polarity along the line when the emf vectors are parted by 180 degrees.

The schematic diagram of a device operating on this principle is shown in Fig. 4-35. To prevent possible misoperation due to changes in power flows at short circuits and after they are cleared and also during short-circuit disconnections of some transmission lines, the control pulse generated by the device

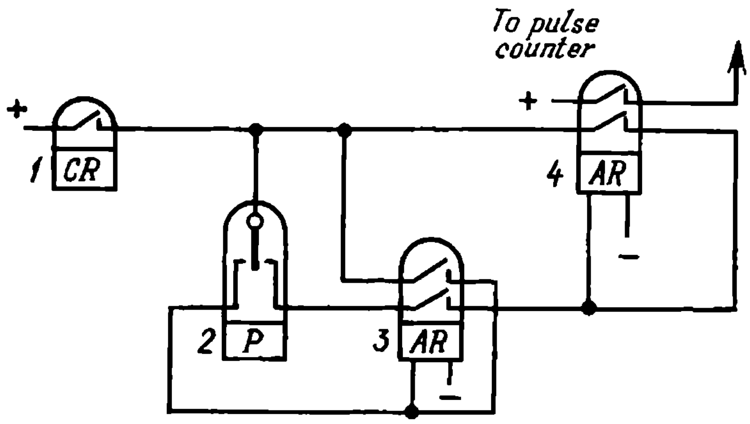


Fig. 4-35. Asynchronous operation detecting device with a real power relay

actuates a pulse number counter. Shown in Fig. 4-36 is a circuit including a two-way power relay *P* whose joint operation with current relay *CR* works out the output signal when the angle δ passes the 180-degree region.

When the voltage vector $\dot{U}_s$ leads the generator emf vector $\dot{E}_g$, the contact *P-2* of the active power directional relay closes (area *cfe*). Functioning of the relay *CR* (area *fdbe*) closes the *2AR* relay which holds itself closed through the contact *2AR-1* even after the power relay has opened the *P-2* contact. Simultaneously the circuit of the coil of the auxiliary relay *1AR* opens.

After the angle δ has passed the 180-degree region, the power relay opens the *P-2* contact and closes the *P-1* contact. As the contact *2AR-2* is closed the circuit of the output relay *3AR* becomes completed. The latter functions and injects the output signal.

If the device is installed at the power station delivering power to a power system and the loss of synchronism is due to the fact that the emf vector $\dot{E}_g$ of the station generators leads the voltage vector $\dot{U}_s$ of the system, then the contact *P-1* closes initially and, after the current relay *CR* has functioned, the coil of the auxiliary relay *1AR* is connected. The contacts of this relay prepare the circuit to close the coil of relay *3AR* (it will pick up after the vector $\dot{E}_g$ is shifted from the *aeb* area to the *dfc* area), open the coil circuit of relay *2AR* (by contact *1AR-3*), and ensure self-holding of the circuit (through contact *1AR-1*). After decreasing the equalizing current in the 270-360 and 0-90 degree regions,

the relay *CR* opens its contact to reset the device. The *3AR* relay functions regardless whether the stability is disturbed in the power system portion that lacks power or in that which has excessive power. If the contact circuit of relay *3AR* is controlled by the contact of relay *1AR*, which is closed after this relay has operated, the output signal will be formed when the stability is disturbed due to the lead of vector $\dot{E}_g$, i.e., because of excessive power at the sending station. The signal may be used to execute the "LESS" command or to disconnect part of the generators. It should be kept in mind that the appearance of the signal will not prevent stability disturbance (the stability has been disturbed as the angle δ is in excess of 180 degrees) and the signal may be used merely for subsequent resynchronization.

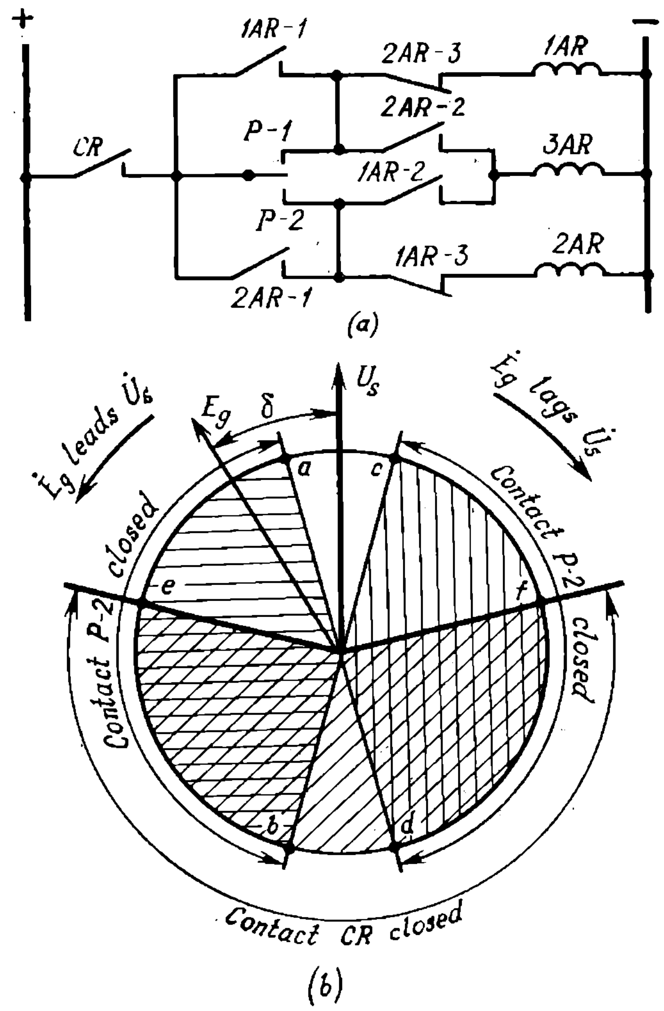


Fig. 4-36. Asynchronous operation detecting element made up of current and real power relays

(*a*) schematic diagram; (*b*) explanatory diagram

(c) **Sectionalizing devices with swing cycle counters.** The automatic sectionalizing device operates after the starting element functions a certain number of times. This simultaneously protects the operation of the automatic device against short circuits. The output relay functions after several pulsations of the electrical quantities causing the contacts of the starting relay to close alternately. The number of actions and the current (voltage) oscillation period at which the output signal is produced are preset.

Mechanical devices, rapid-response auxiliary relays and electronic devices may be used as cycle counters. Counters employing single-coil rapid-response auxiliary relays as quick operating (responding to oscillations of small periods, up to 0.1 s) units easy to adjust in service are the ones mostly used. The most popular counter circuit is shown in Fig. 4-37.

One of the instantaneous automatic sectionalizing devices may be used as the starting element. This device is so changed that its action cannot be discriminated against short circuits (this function being performed by the counter). The current, voltage and impedance starting relays should be connected so that the counter is also triggered with stability disturbances in operation with incomplete number of phases. This condition is best met by connecting the relay to the current of phase conductors *A*, *B* and *C* or to the current of one or two

phases and zero-sequence current. The relay contacts are connected in parallel. Fig. 4-37 shows a circuit variant in which the starting element made up of current relays is connected to each phase conductor of the line. To improve the response of the starting element to asynchronous currents and obtain better isolation against load currents, the starting element often utilizes current and voltage relays and series connection of the contacts of these relays.

The experience gained from the service of sectionalizing devices furnished with a counter for the operation cycles of the starting element has shown that

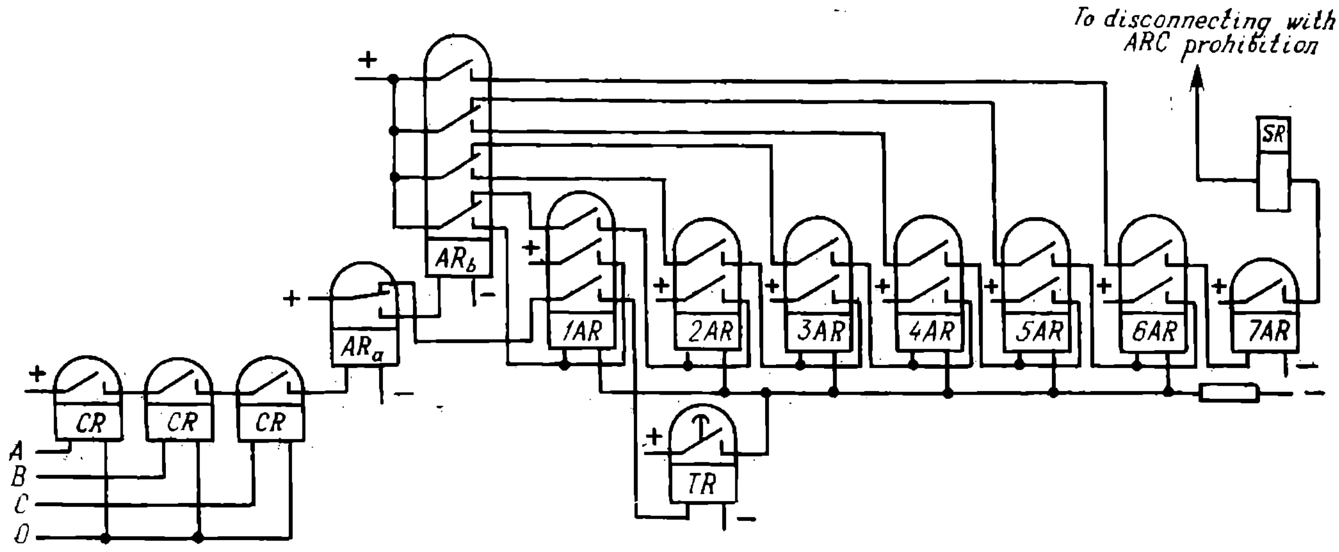


Fig. 4-37. Circuit diagram of a sectionalizing device

their design must take into account the multi-shot operation of lightning arresters during intensive thunderstorm disturbances, current and voltage surges due to short circuit, its clearing and subsequent line reclosure by the ARC device where the short circuit persists, etc.

The circuit is designed to send a disconnecting pulse at the third trip-and-closure cycle. The output relay *7AR* functions after the prescribed number of operating cycles of the starting element is accomplished and if the time during which the starting element contacts remain open does not exceed the rated value. In the case of excessive time the device resets. The number of trip-and-closure cycles, usually from three to six, is determined by the operating selectivity of the automatic sectionalizing devices used in the power system. The time relay *TR* is given a setting of 2.0 to 2.5 s which exceeds the time the line breakers remain open in the automatic reclosure cycle.

Figure 4-38*a* shows changes in the starting element current as it pulsates during asynchronous run with a period of T. The open state time of the starting element contacts employed by the automatic sectionalizing device is t_s. Points *1*, *2*, ..., *7* correspond to the pickup instants of relays *1AR*, *2AR*, ..., *7AR* (Fig. 4-37). Fig. 4-38*b* illustrates how the current changes in the starting element circuit in case of a short circuit cleared within time $t_{s.c.1}$, line reclosure by the ARC device after time t_{ARC} and repeated tripping within time $t_{s.c.2}$.

The operating time setting of the relay *TR* (Fig. 4-37) t_t must be greater than t_s, but less than t_{ARC}.

(d) **Sectionalizing devices controlling asynchronous run within a specified time.** A power system is sectionalized into asynchronously operating parts only when asynchronous run persists beyond the preset time. The use of such devices

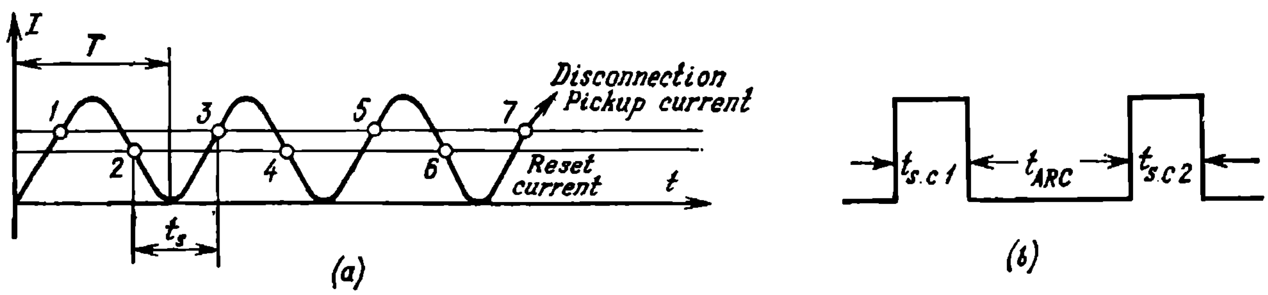


Fig. 4-38. Changes in current flowing in the circuit of starting element of a sectionalizing device
(*a*) in asynchronous operation; (*b*) in ARC operation with a persisting short circuit

allows various units installed at different points of the power system to be discriminated in time. More than that, it enables the sectionalizing technique to be used only after the other methods have failed to promote resynchronization of the power system.

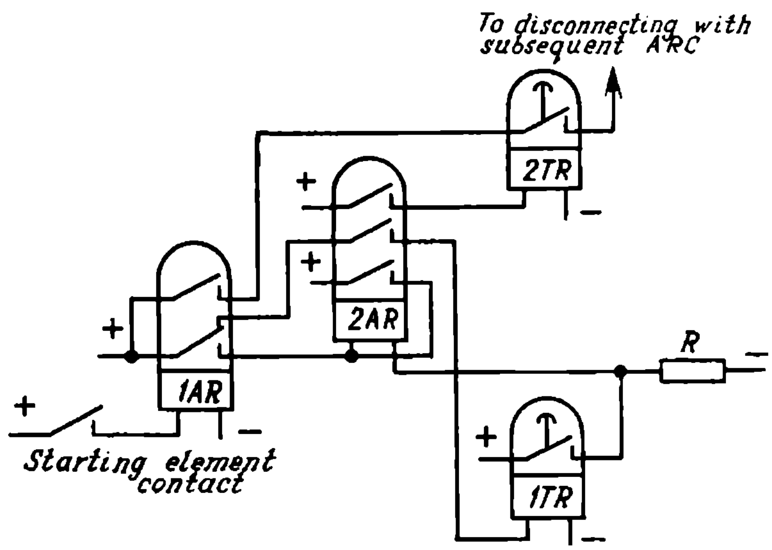


Fig. 4-39. Sectionalizing device with asynchronous operation duration controlled

Shown in Fig. 4-39 is a variant of the device circuit. The power system is sectionalized in case of long asynchronous operation which continues in excess of the time period set on the relay *2TR*. Operation of the starting element closes the relay *1AR* and then relay *2AR*. The latter remains closed until the time relay *1TR* controlling the swing period acts. The relay *2AR* closes the relay

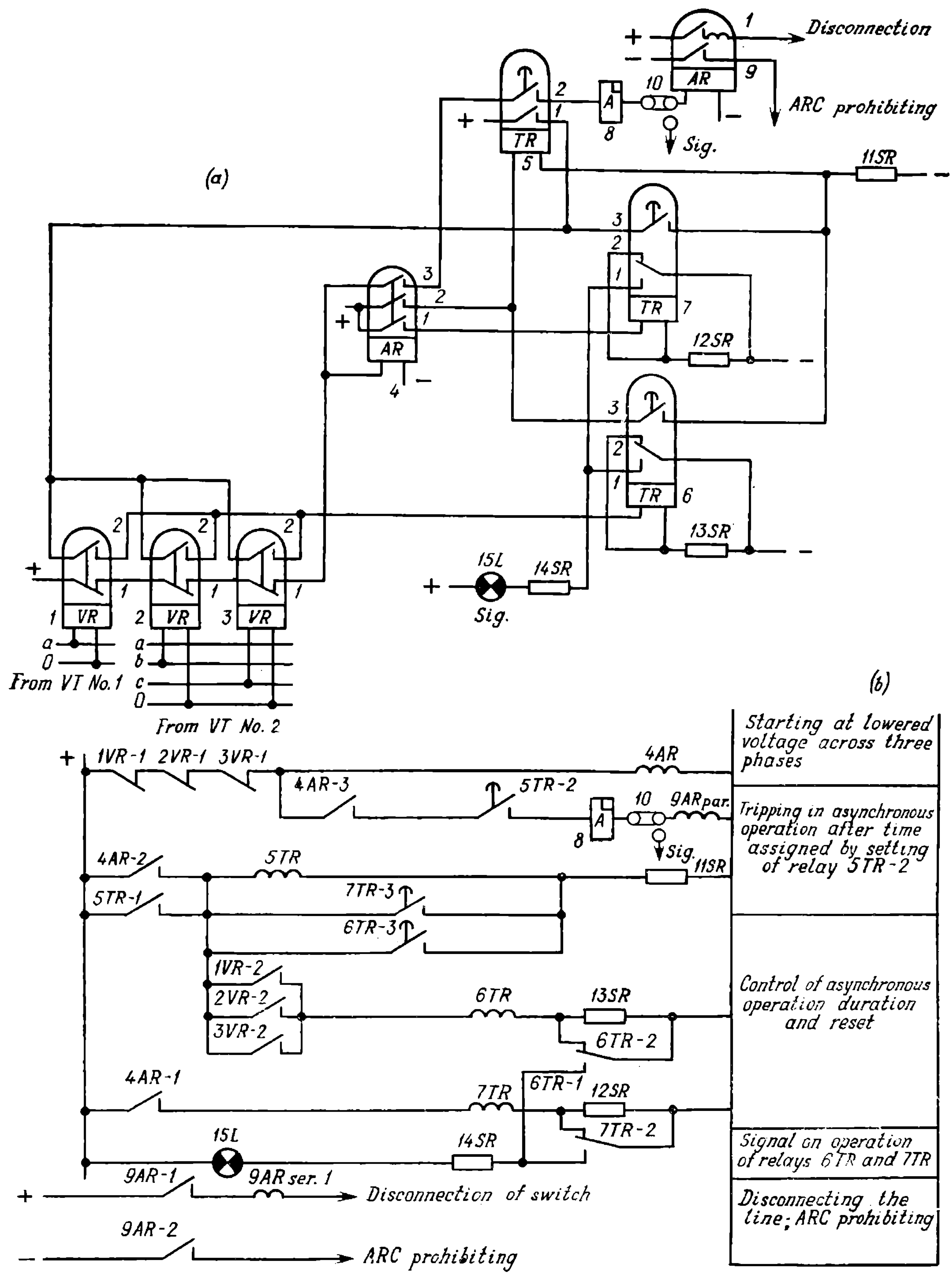


Fig. 4-40. Sectionalizing device in asynchronous operation

(a) combined diagram; (b) developed diagram. Contact positions correspond to deenergized state of relay coils

2TR whose operating time can be adjusted from 10 to 15 s or 0.5 to 3 min. The relay *2TR* will close its contacts only in the case of long asynchronous operation, as restoration of normal parallel operation stops pulsation of the starting element contacts making the relay *1TR* function and the relays *1AR* and *2TR* reset.

Figure 4-40 shows the circuit of a device utilizing the above-described operating principle with starting voltage relays. To avoid unwanted starting at faults in the voltage circuits, two sets of voltage relays are used. The *6TR* and

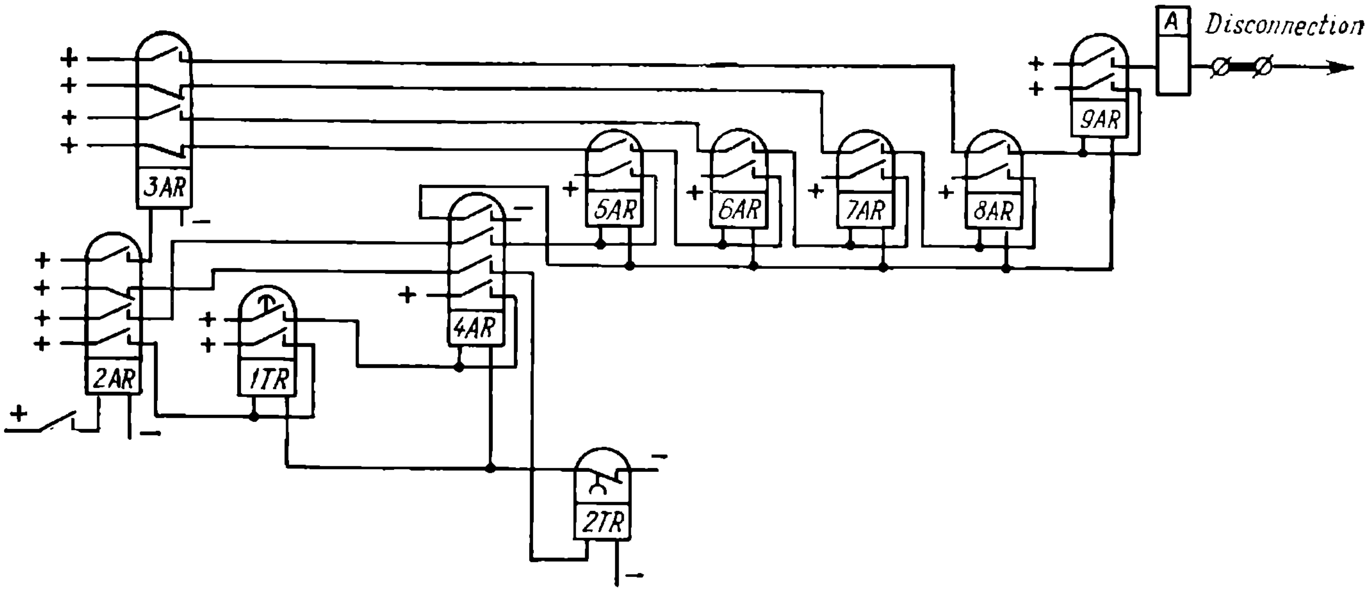


Fig. 4-41. Sectionalizing device detecting prolonged asynchronous operation

7TR relays are for control of both the closed and opened states of the starting elements under asynchronous conditions. The total period during which the device controls the asynchronous operation is determined by the setting of time relay *5*.

Another principle underlying the automatic sectionalizing devices which control asynchronous operation within a specified period is explained by the circuit shown in Fig. 4-41. Loss of synchronism is detected due to the fact that the counting part of the device operates only after the starting element has functioned and the time relay *1TR* has measured the specified time.

Of the above-considered variants of the devices operating under asynchronous conditions with a time delay, this circuit is the most flexible as it allows the current, voltage, impedance and power relays and their combinations to perform the function of the starting element.

When arranging the sectionalizing devices in the power system their possible failures due to troubles in the relaying part or in the switch gears must be taken into consideration. The required margin is obtained either by installing individual sets at the opposite ends of the line and giving them similar settings or by fitting the sets at different points of the network giving them selective operation ability which is obtained either by adjustment to a different

number of cycles or to different periods of asynchronous operation control. In addition, sectionalizing of the power system at the predetermined points under asynchronous conditions is one of the duties assigned to the operators.

4-6. Separation of Small Thermal Power Stations from Large Hydroelectric Stations when Speed of Hydroelectric Generators Increases

A number of power supply systems includes powerful hydroelectric stations operating in parallel with relatively low-power thermal stations. Most of the hydroelectric station's output is usually delivered through tie lines to the receiving part of the system. If a tie line is disconnected, the hydroelectric station may still work in parallel with a thermal power station. The hydroelectric generators begin accelerating and, as the regulating system of the hydroelectric generators may not have time to rapidly reduce their speed, it may rise to 120-130 per cent of the rating. The normal system regulating the speed of hydroelectric generators allows for this increase as they are low-speed machines and this speed rise is not dangerous.

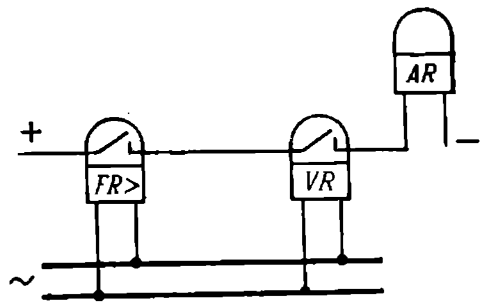


Fig. 4-42. Sectionalizing device for power systems when load frequency rises

FR — overfrequency relay; *VR* — voltage relay; *AR* — auxiliary relay

As a result of increased speed of the hydroelectric generators the turbogenerators operating in parallel are also accelerated (as the hydroelectric and turbogenerators continue to operate synchronously). When this happens, the speed of the turbogenerators at the thermal power station may exceed their mechanical strength. Since the turbogenerators are high-speed machines, their speed limit is only 110 to 112 per cent of the rating. When the speed limit is exceeded, the appropriate automatic safety devices come into operation and shut-off steam to the turbine. However, as the generator is not disconnected from the circuit, it will run as a motor and increase its speed. The final result may be a damage to the machine.

This fault is prevented by an automatic sectionalizing device responding to a rise in the frequency, the device being installed on the link between the thermal and hydroelectric power stations. Use is made of instantaneous automatic devices (Fig. 4-42). To provide mutual redundancy, two sets of automatic devices are placed at the ends of the tie line whose disconnection is planned allowing also for the thermal power station to supply the load assigned to it. The frequency relays are set to operate between 52.0 to 53.5 Hz.

The frequency relay connection circuit controls the operational current circuit by the contact of a voltage relay which is closed at the existing voltage but opens as the voltage drops. The operating setting voltage is 70 to 80 per cent of the rated value. The circuit employs a voltage relay because the frequency relays may close their contacts and make the output relay misoperate

due to interruptions in the applied voltage if a fault occurs, for instance, in the circuits of the voltage transformers.

To prevent overspeeding of thermal turbines, a proposal was made to simultaneously disconnect the generator from the power system when the automatic safety device comes into action. For this, the circuit tripping the generator switch gear must close when the automatic safety device operates. As compared to the use of automatic devices utilizing a frequency responsive relay, this method is less perfect as it predetermines the stopping of the thermal prime mover even in the cases when the automatic safety devices misoperate.

Automatic control devices responsive to the frequency increase are installed not only on the transmission lines between thermal and hydroelectric power stations, but on the hydroelectric stations too. Their function is to disconnect the hydroelectric generators with a view to preventing an increase in the frequency after disconnection of the tie links to the receiving system. These automatic devices are set within 51.0-51.5. Hz, i.e., somewhat lower than those of the automatic sectionalizing devices installed on the links to the thermal stations. Thus, the latter serves as a stand-by and comes into action if the frequency responsive automatic device installed on the hydroelectric station turns out to be ineffective or fails to function.

The circuits employed by the automatic devices designed for disconnecting the hydroelectric generators when the frequency rises are similar to those described above.

4-7. Preventing Misoperation of Protective Relaying

Since the currents and voltages encountered in overloads, synchronous swings and asynchronous operation are commensurate with the short-circuit currents and voltages, all type protection devices, except differential and those responsive to the backward and zero sequence of electrical quantities, can function under the considered operating conditions without short circuits. Subject to the effect of asynchronous operation in particular are the instantaneous protection devices, if they are not discriminated in their operation against the changes in electrical quantities occurring under such operating conditions. The time delay protection devices used in loss of synchronism can regularly close and open the time-delay element. If the closed state time of the starting element exceeds the time within which the action of the time-delay element remains effective the protective device will function.

Misoperation of protective relaying is prevented as follows:

(a) By the use of special blocking units ("swing blocking") which detect short-circuit conditions and permit in this case protective relaying operation. When there is no short circuit, the operational circuit of the protection remains open regardless of changes in the electrical quantities (increase in current, decrease in voltage).

(b) By using devices which possess reduced sensitivity to the heavy load currents as the starting elements of the relaying protection. Examples are the

use of voltage relay blocking units, and distance starting elements having special characteristics.

Let us consider the operation of the above-mentioned devices.

The blocking unit preventing misoperation of the protection devices in the case of synchronous swings, asynchronous operation and overloads can be fulfilled on the following principle. During swings or asynchronous operation the electrical quantities vary gradually but with short circuits they change suddenly, in this case operation of the protection device is permitted, if the relays having the different settings function simultaneously but is prohibited if they do not function simultaneously. When electrical quantities of backward or zero sequence appear, the action of the protection is allowed regardless of the operation of blocking units. In design, this principle may be accomplished by the use of an element that responds to a specified rate of change in the electrical values in place of relays having different operating settings. Such an element can be obtained by connecting relays to the instrument transformers through a differentiating network.

In practice, current and impedance relays of different sensitivity have been used for the purpose. Service experience has shown that the devices may misoperate when the electrical quantities vary within a time length less than 0.7 to 1 s. Therefore, the blocking units used in the USSR operate on another principle which has justified itself over many-years service.

The protection is started and remains effective within a time period sufficient to detect a short-circuit occurrence in the zone under protection when an asymmetric state of the system appears, even if only for an instant (5 to 10 μs). The actuating circuit of the protection system is not placed into operation when the protection starting elements function in the absence of asymmetry conditions. When protection devices are used in power systems allowing prolonged asynchronous operation the actuating circuit of the protection system opens for a length of time exceeding the period of the asynchronous cycle. The latter principle is employed in the ДЗ-500 protection system of 400 or 500 kV lines.

The principle underlying the operation of the device responding to prolonged or short-time asymmetry of electrical quantities in a three-phase circuit can be seen from the diagram given in Fig. 4-43*a*. This device was designed by the author in 1938, inventor's certificate No. 61423, April 10, 1938. In the case of synchronous swings, asynchronous operation or overloads unaccompanied by short circuits, the protection device will not function since relay *4* responding to asymmetry of the electrical quantities, like a backward-sequence relay or a relay responding to the sum of the backward and zero sequences of electrical quantities, does not function as contact *4-1* is closed. With a short circuit of any type contact *4-1* opens. If the short circuit is asymmetric, contact *4-1* stays open all the time the asymmetry is present. If the short circuit is symmetric between the three phases the contact opens only for a short time.

Opening (if only for an instant) of contact *4-1* of the starting relay deenergizes the coil of auxiliary relay *1* and makes it complete the protection circuits. Relay *1* is changed over to the initial excited position after the action of time

relay *3* whose setting exceeds the time for clearing the fault in the protected zone or it is greater than the time for indicating the fault in the protected zone in the instantaneous measurement schemes. The voltage *V* and impedance *Im* relays guard against repeated making of the protection circuits after clearing a symmetric short circuit.

Contact *4-2* of the starting relay prevents the blocking device from repeated starting after an asymmetric short circuit is cleared. To make the circuit operation accurate, relay *2* is provided, in which the armature return is delayed by 0.1 to 0.2 s after the relay coil is deenergized.

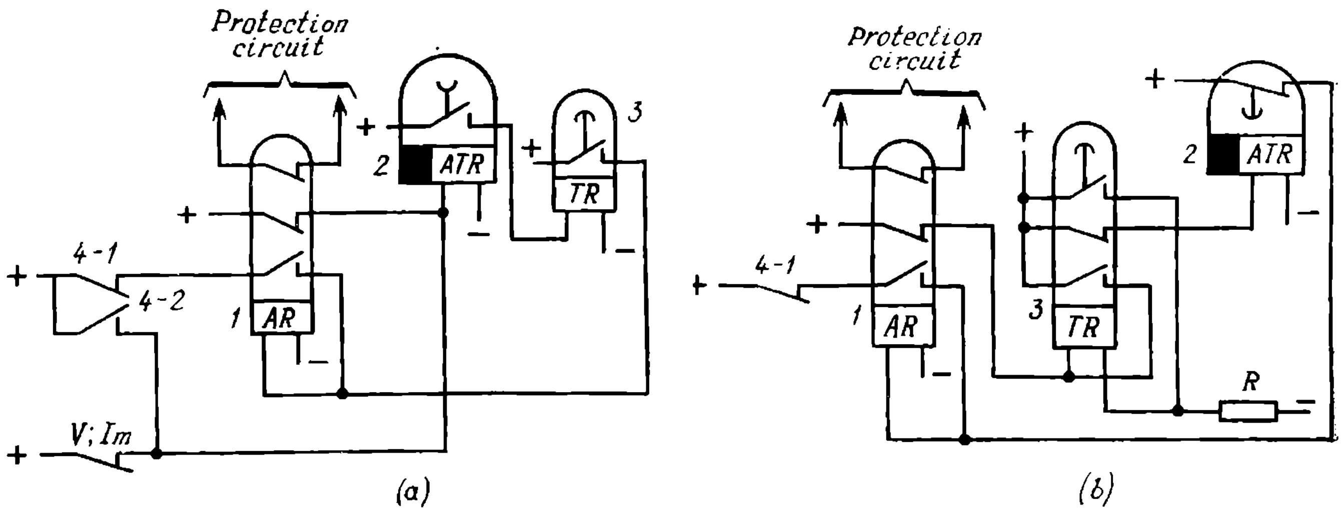


Fig. 4-43. Swing and overload blocking circuit responding to asymmetric electrical quantities (though of very short duration)

(*a*) circuit with instantaneous readiness for repeated operation; (*b*) circuit with readiness for repeated operation after preassigned time; *1* — auxiliary relay; *2*, *3* — time relays; *4-1* and *4-2* — relay contacts responding to asymmetry in electrical quantities; *V*, *Im* — contacts of voltage or impedance relay (position of contacts corresponds to deenergized state of relay)

The device circuit prevents improper functioning of the instantaneous protection devices in the unfaulted parts of the power system in case of synchronous swing or asynchronous operation due to ill-timed clearing of a short circuit. In such a case, the protection is taken out of operation after a sufficient lapse of time for it to act in the protected zone. This time is 0.2 s for instantaneous protection devices in which a cascading action need not be considered. This length of time is insufficient to allow the supply emf vectors, even at heavy short circuits, to part so that misoperation of the protection is brought about.

The circuit in Fig. 4-43*a* provides instantaneous readiness of the protection after clearing a short circuit. The circuit in Fig. 4-43*b* provides readiness of the device to operate repeatedly after the lapse of preassigned time. In this event, no undervoltage or impedance relay is required and the readiness time of the circuit to repeat the operation must overlap the short-circuit clearing time. The disadvantage of the latter version is that after each current surge (operation of lightning arresters) the instantaneous protection on many lines in the power system may be put out of action. Such a design, however, proves to be

good when use is made of the automatic reclosing of single tie lines without checking for synchronism. The instant an asynchronous closure is performed, backward- and zero-sequence components appear in the system, but the protection performs no false operation as its circuits are opened by the swing blocking unit and the time for restoring the readiness to repeat the operation of the blocking unit must be adjusted so that this repeated operation can take place only after the tie line is automatically reclosed.

The devices which start the protection system when backward-sequence currents and voltages appear are connected to the instrument transformers via the backward-sequence current and voltage filters. Let us consider the operation of a resistance-capacitance filter or backward-sequence voltages, which are often delivered together with the blocking unit.

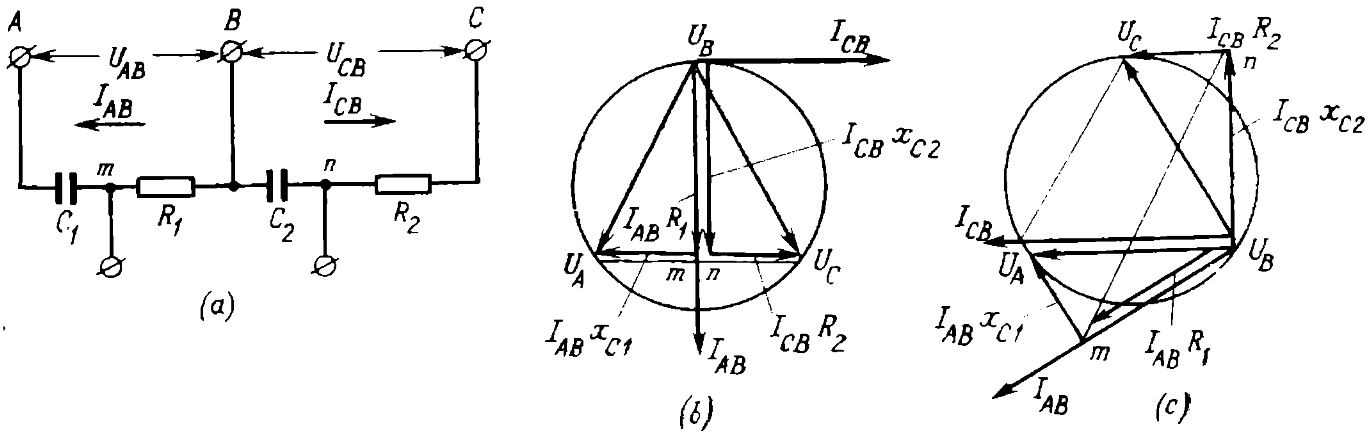


Fig. 4-44. Resistance-capacitance filter for backward-sequence voltage
(a) circuit diagram; (b) potential diagram when forward-sequence voltage is applied to filter; (c) same, when backward-sequence voltage is applied to filter

For the diagram of the filter see Fig. 4-44. In order to make the potentials at points m and n equal and prevent the relay connected to these points from responding to the zero- and forward-sequence voltages, the filter is connected to the interphase voltages and the arm ratios are as follows

$$R_1 : x_{C1} = x_{C2} : R_2 = \frac{\sqrt{3}}{2} : \frac{1}{2} \tag{4-29}$$

The mentioned ratios are obtainable directly from the diagram in Fig. 4-44*b*.

A voltage proportional to the backward-sequence potential appears across the terminals m and n with any type of short circuit.

A symmetric short circuit causes sudden changes in the values of currents and voltages. Owing to the inductance of electrical circuits free currents and voltages which are superimposed upon the induced currents and voltages appear in the power system.

The initial values of free currents are

$$\left.\begin{aligned} i_{f\,a} &= -i_{sc\,a} \\ i_{f\,b} &= -i_{sc\,b} \\ i_{f\,c} &= -i_{sc\,c} \end{aligned}\right\} \tag{4-30}$$

If a dead (metal-to-metal) short-circuit occurs where

$$u_{sc\,a} = u_{sc\,b} = u_{sc\,c} = 0 \tag{4-31}$$

then the voltages appear

$$\left.\begin{aligned} u_{f\,a} &= u_{ph\,a} \\ u_{f\,b} &= u_{ph\,b} \\ u_{f\,c} &= u_{ph\,c} \end{aligned}\right\} \qquad (4\text{-}32)$$

In expressions (4-30) to (4-32) i_{sc} and u_{ph} are instantaneous values of short-circuit current and phase voltage under prefault conditions.

Figure 4-45 illustrates how the free currents and voltages vary in time from the instant the fault occurs. The current and voltage systems are considered separately. The diagram in Fig. 4-45*a* corresponds to the short-circuit instant at which the *A* phase current amplitude

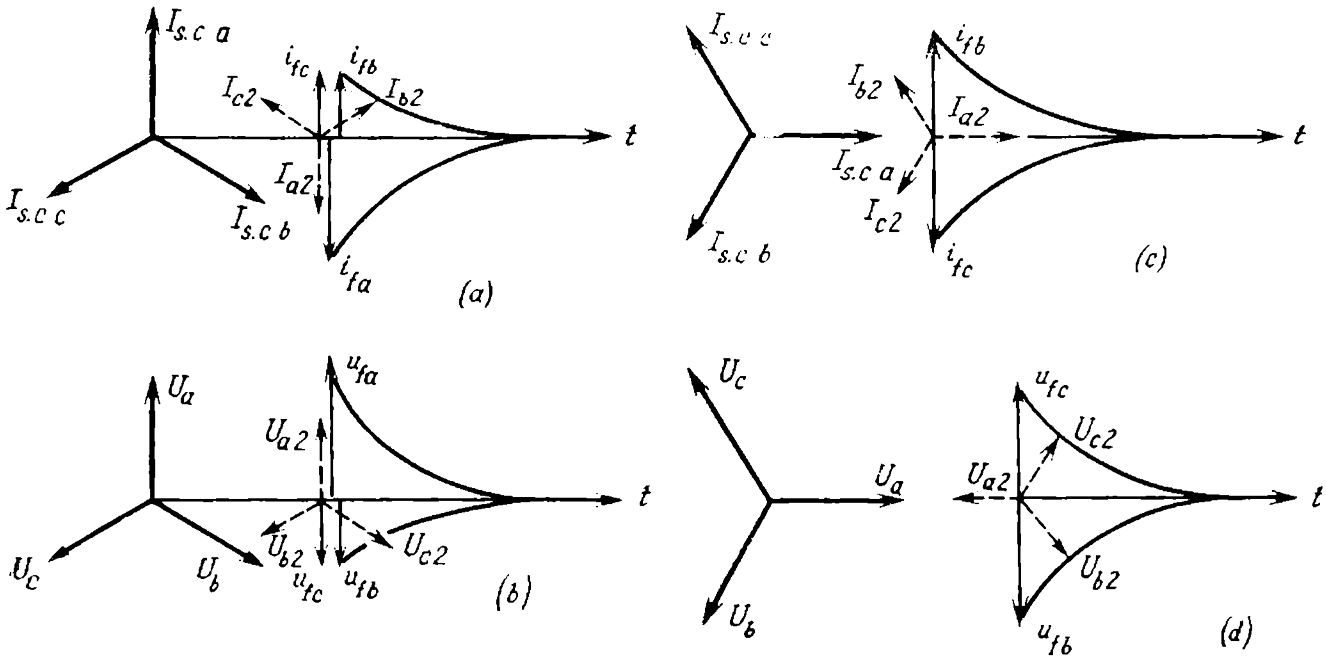


Fig. 4-45. Free currents, voltages and backward-sequence components on secondary sides of instrument transformers during symmetric three-phase short circuit in power system

is at its maximum. Figure 4-45*c* shows a short circuit arising at the instant the *A* phase current amplitude is at 0. Analogous diagrams for the voltages are shown in Fig. 4-45*b*, *d*.

The system of free currents and voltages at the instant they arise is asymmetric and a surge of voltages occurs at the output of the backward-sequence filter. The induced currents and voltages with a three-phase short circuit are symmetric. Therefore they will cause no emf at the output of the backward-sequence filter and may be neglected, except for their effect on unbalance currents.

The initial value of free current and voltage at backward sequence can be easily determined

$$\left.\begin{aligned} I_2 &= 0.5i_{f\,a} = 0.5I_{sc.\,m} \text{ (Fig. 4-45}a) \\ I_2 &= \frac{1}{\sqrt{3}}\, i_{f\,b} = 0.5I_{sc.\,m} \text{ (Fig. 4-45}c) \\ U_2 &= 0.5u_{f\,a} = 0.5U_{ph.\,m} \text{ (Fig. 4-45}b) \\ U_2 &= \frac{1}{\sqrt{3}}\, u_{f\,b} = 0.5U_{ph.\,m} \text{ (Fig. 4-45}d) \end{aligned}\right\} \qquad (4\text{-}33)$$

where $I_{sc\cdot m}$ and $U_{ph\cdot m}$ are the maximum amplitude values of the current and voltage.

When a short-circuit occurs at a certain distant point K on the busbars of a supplying substation G the residual voltage is not equal to zero. Therefore, a backward-sequence voltage appears in this event at the beginning of a symmetric short circuit

$$U_2^G = 0.5\,(U_{ph.\,m} - I^{(3)}_{sc.\,m} z_{1GK}) \tag{4-34}$$

where $I^{(3)}_{sc\cdot m}$ = three-phase short-circuit current from point G to point K
z_{1GK} = forward-sequence impedance from point G to point K

When a symmetric three-phase short circuit occurs a voltage appears at the output of the resistance-capacitance filter for a short length of time, this is due to the discharge of the capacitors and different time constants of the filter arm circuits.

Let us find out which voltages appear across the m and n filter terminals (Fig. 4-44) at the instant the three phases are simultaneously closed at the input. Connected to these terminals is the starting relay blocking against swings and overloads. The value of the voltage across the m and n terminals is determined from the analysis of the transient process taking place when capacitors C_1 and C_2 discharge into resistors R_1 and R_2 and the relay coil.

To simplify the analysis, assume that the relay resistance is infinite in value, i.e., the secondary terminals of the filter are open.

Voltages across the capacitors C_1 and C_2 under the prefault conditions are determined as follows

$$U_{C1} = \frac{1}{2} U_{AB} e^{-j60} \tag{4-35}$$

$$U_{C2} = \frac{\sqrt{3}}{2} U_{CB} e^{-j30} \tag{4-36}$$

The voltage across the open terminals of the filter is determined by the value of the projection of the vector sum of the voltages U_{C1} and U_{C2} on the axis of ordinates

$$\dot{U}_{mn} = \frac{1}{2}\dot{U}_{AB} e^{-j60} + \frac{\sqrt{3}}{2}\dot{U}_{CB} e^{-j30}$$

$$\dot{U}_{mn} = 0.5 e^{-j60}\,(\dot{U}_{AB} + \sqrt{3}\,\dot{U}_{CB} e^{+j30}) \tag{4-37}$$

where $\dot{U}_{mn}$, $\dot{U}_{AB}$, and $\dot{U}_{CB}$ are the effective values of voltages

In time t the instantaneous values of the voltage across the filter terminals

$$u_{mn}^{(t)} = u_{C_1(t=0)} e^{-t/T_{\mathrm{I}}} + u_{C_2(t=0)} e^{-t/T_{\mathrm{II}}} \tag{4-38}$$

where T_{I} and T_{II} = time constants of circuits I and II
$U_{C1(t=0)}$ and $u_{C2(t=0)}$ = instantaneous values of the voltages across the capacitors at the instant a short circuit occurs

The constant T_{I} is

$$T_{\mathrm{I}} = C_1 R_1 \tag{4-39}$$

where

$$C_1 = \frac{1}{\omega x_{C1}}$$

Since $R_1 : xC_1 = \frac{\sqrt{3}}{2} : \frac{1}{2} = \sqrt{3} : 1$, then

$$x_{C_1} = R_1 1/\sqrt{3}, \text{ consequently}$$

$$T_{\mathrm{I}} = \frac{R_1\sqrt{3}}{\omega R_1} = \frac{\sqrt{3}}{\omega} = 0.0055$$

The constant T_{II} is

$$T_{II}=C_2R_2 \tag{4-40}$$

where

$$C_2=\frac{1}{\omega x_{C2}}$$

Since

$$R_2:x_{C2}=\frac{1}{2}:\frac{\sqrt{3}}{2}=1:\sqrt{3},\text{ then}$$

$$x_{C2}=\sqrt{3}\,R_2,\text{ consequently}$$

$$T_{II}=\frac{1}{\omega}\,\frac{R_2}{x_{C2}}=\frac{1}{\omega\sqrt{3}}=0.00185$$

Shown in Fig. 4-46 are the curves illustrating how the voltages across the m and n terminals decay with time. Even in the case of the most unfavourable phase combinations of

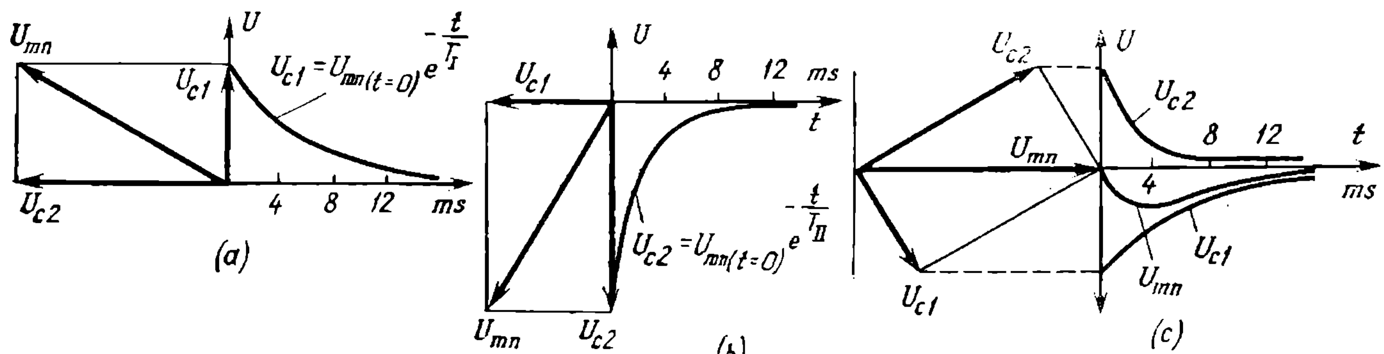


Fig. 4-46. Voltage variation across secondary terminals of filter (Fig. 4-44) with three-phase short circuit at primary terminals
(a) $U_{C2\,(t=0)}=0$; (b) $U_{C1\,(t=0)}=0$; (c) $U_{mn\,(t=0)}=0$

voltage vectors during a short circuit, when the initial value of U_{mn} is null (Fig. 4-45c), after some time a voltage about 16 per cent of the interphase voltage amplitude appears across the filter terminals.

To improve the sensitivity, use may be made of two voltage filters, one connected to phases A, B, and C and the other to phases B, C, and A or C, A and B. If the phase combination is unfavourable for the first filter, then for the second filter the minimum value of the initial voltage U_{mn} will be $\sqrt{3}/2$ of the interphase voltage amplitude.

In a number of cases it is possible to discriminate against the currents appearing in asynchronous operation even without the use of blocking devices made for the purpose. For example, a current cutout will not respond to asynchronous operation currents if its setting

$$I_{op}\geqslant k_s I_{m.a.o} \tag{4-41}$$

where k_s = safety factor equal to 1.1 to 1.2
$I_{m.a.o}$ = maximum current of asynchronous operation when the emf vectors are 180 degrees apart

The underimpedance protection will not respond to the currents and voltages of asynchronous operation if its setting

$$z_{op} < z_{1GK} \tag{4-42}$$

where z_{1GK} is the forward-sequence impedance from the relay location to the electric centre of the system.

Desensitization of protection operation at swings and asynchronous operation is obtained also by the use of special starting elements which in conjunction with the swing blocking device lessen the likelihood of protection misoperation in case of short circuits during swinging or prolonged asynchronous operation and also at heavy load current flowing in the circuit of the equipment under protection.

Special starting elements of protection with reduced response to currents arising due to overloads, synchronous swings and asynchronous operation. As starting elements reducing the protection sensitivity to load currents and currents from synchronous swings and asynchronous operation, use may be made of relays or other devices which limit (on the complex plane) the working protection area near the characteristic of the line under protection.

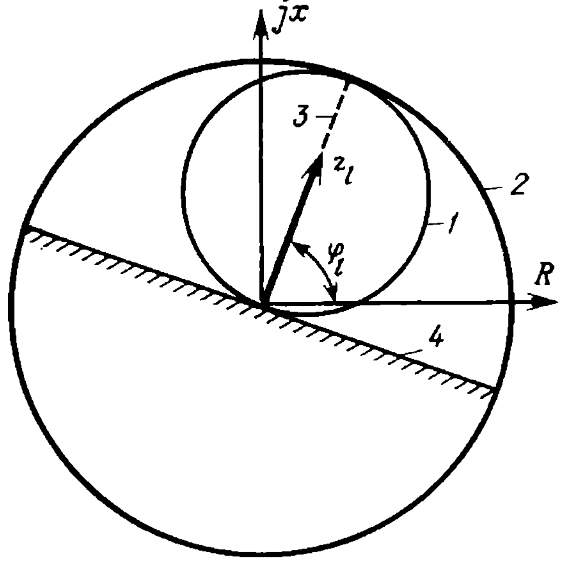


Fig. 4-47. Impedance relay characteristics plotted as R- and jx-axes values
1 — action zone of directional impedance relay; 2 — action zone of impedance relay; 3 — characteristic of protected line having impedance z_l; 4 — characteristic of directional power relay

The directional impedance relay is most commonly used for this purpose. The working characteristic of this relay plotted as R- and jx-axis values is given in Fig. 4-47. The working area (circle *1*) is relatively small in size. By way of comparison the figure shows the operating zone of an impedance relay (circle *2*) possessing the same sensitivity to short circuits on protected line *3* as the directional impedance relay. Straight line *4* shows the operating characteristic of a power direction relay which is usually used in conjunction with the impedance relay.

Directional relays of any type satisfy the condition

$$\left.\begin{aligned} M_b &= k_1^2U^2 \\ M_o &= k_1Uk_2I\cos(\varphi-\alpha) \end{aligned}\right\} \tag{4-43}$$

where M_b and M_o are the braking and operating torques on the relay.

When in balance, neglecting the friction and spring effect

$$k_1^2U^2 = k_1Uk_2I\cos(\varphi-\alpha)$$

or

$$\frac{U}{I}\frac{1}{\cos(\varphi-\alpha)} = \frac{k_2}{k_1} = \text{const}$$

i.e.

$$z = z_{pick\text{-}up} \cos(\varphi - \alpha) \qquad (4\text{-}44)$$

where I = current in the current circuit of the relay
U = voltage at the relay location
α = internal shift angle of the relay
φ = angle between current and voltage
$z_{pick\text{-}up}$ = operating setting of the relay
k_1 and k_2 = proportionality factors

Expression (4-44) represents the equation of a circle having diameter $z_{pick\text{-}up}$. The internal angle of the relay (α) is generally chosen equal to the full impedance angle (φ_l = 60 to 85°) of the transmission line under protection.

The operating region of the relaying protection near the characteristic of the line being protected can be narrowed also by phase limiters. The contacts

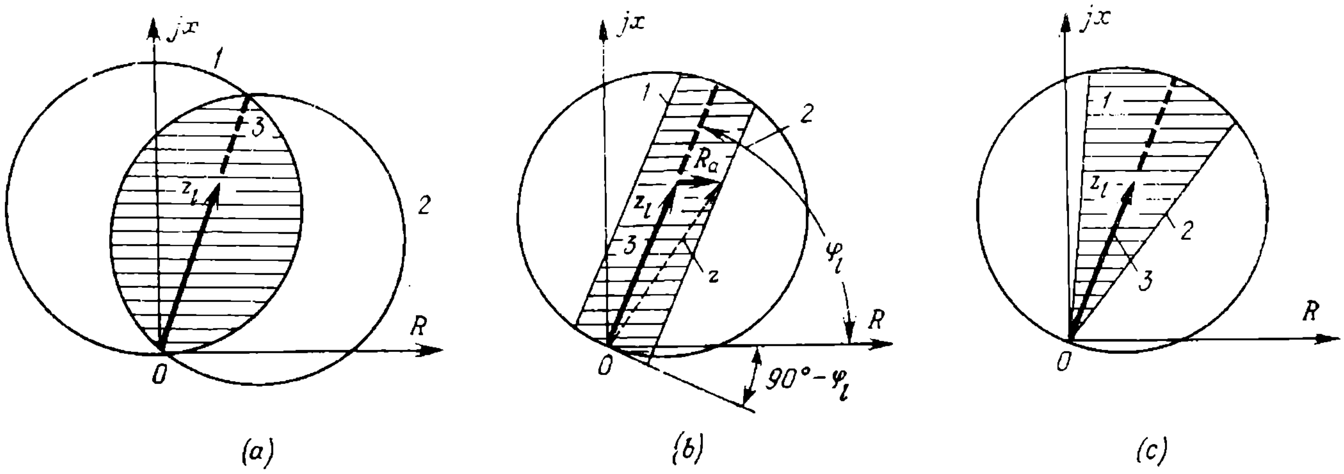


Fig. 4-48. Characteristics of phase limiters

(*a*) operating area of two directional impedance relays with different internal angles and series-connected contacts; (*b*) same, for two impedance relays with straight-line characteristics and a directional impedance relay; (*c*) same, for two directional power relays and a directional impedance relay (*1*, *2* — characteristics of phase limiters; *3* — characteristics of protected line having impedance z_l)

of the phase limiters are connected in series with the contacts of the main protection. If two directional impedance relays with different internal angles (Fig. 4-48*a*) are used as the phase limiters the working area of joint operation is determined by the shaded area. The function of phase limiters can be also performed by impedance relays having an inclined straight-line characteristics or directional relays (Fig. 4-48*b* and *c*).

Impedance relays with inclined straight-line characteristics may be of various types provided the following conditions are met

$$\left.\begin{aligned} M_b &= k_1 U k_2 I \cos(\varphi + \alpha) \\ M_o &= k_2^2 I^2 \end{aligned}\right\} \qquad (4\text{-}45)$$

When in balance

$$k_1Uk_2I\cos(\psi+\alpha)=k_2^2I^2$$

or

$$\frac{U}{I}\cos(\varphi+\alpha)=\frac{k_2}{k_1}=\text{const}$$

i.e.

$$z\cos(\varphi+\alpha)=z_{pick\text{-}up} \tag{4-46}$$

The pick-up setting is so selected that straight-line *2* is parallel to straight-line *3* and spaced from it at a distance

$$z_{pick\text{-}up}=R_a\sin\varphi_l \tag{4-47}$$

where R_a = arc resistance
φ_l = angle of the line impedance

Directional relays are far simpler than the impedance relays, for which reason they are often used for making phase limiters.

In discrimination against load currents only one phase limiter is acceptable to prevent misoperation of the protection at small load angles, say, of less than 30 degrees.

Figure 4-49 is an example of connecting a phase limiter. It is supposed that the impedance of the first and second protection regions is far less than that of the load, and that the impedance of the third region is commensurate with it. The circuit of the first region of distance protection is controlled by the contact *S-1* of the swing blocking unit. This contact closes, with asymmetry in the electrical quantities at the instant a short circuit occurs, for a period sufficient (0.2-0.3 s) to permit functioning of the protection. The circuit of the second region of distance protection whose operating time is 0.4 s and more is controlled by the contact *1AR-2* of the auxiliary relay.

The relay *1AR* picks up, if a fault occurs in the second protection region and the contact *S-2* of the swing blocking unit closes simultaneously with the contact *2I* of the impedance measurement element of the second region. The circuit *2I — 1AR-1* holds the relay *1AR* closed until the contacts *2I* open. In the case of repeated closure of the contact *2I* owing to swings or loss of synchronism the relay *1AR* picks up no more as the *S-2* contacts remain open.

The circuit of the third region of distance protection has a time delay of 1 s or more and is controlled by the *2AR-2* contact of the auxiliary relay. Since the pick-up impedance of the third region is commensurate with the load impedance, the relay *2AR* picks up, provided the circuit is completed by the contact of the phase limiter *PL* or by the contact of backward-sequence current (voltage) relay I_2 (U_2), i.e., with a short circuit. In this instance the coil of the relay *2AR* is closed by the contact of the relay *3I* in a way similar to that when closing the relay *1AR* by the impedance measurement element *2I* of the second region described above. When a phase limiter *PL* is fitted to each protection phase, the *PL* contact need not be by-passed by the I_2 (U_2) contact. This adds to the perfect operation of the third region.

If the function of the phase limiter is performed by a directional power relay of the cosine type responsive to the power of $P = UI \cos \varphi$ (U and I are voltage and current applied to the relay; φ is the angle between the current and voltage vectors), the coils of the power relay may be connected to the current of phase A and voltage of phase B. Here operation of the third region of distance protection will be possible if the current lags the same phase voltage

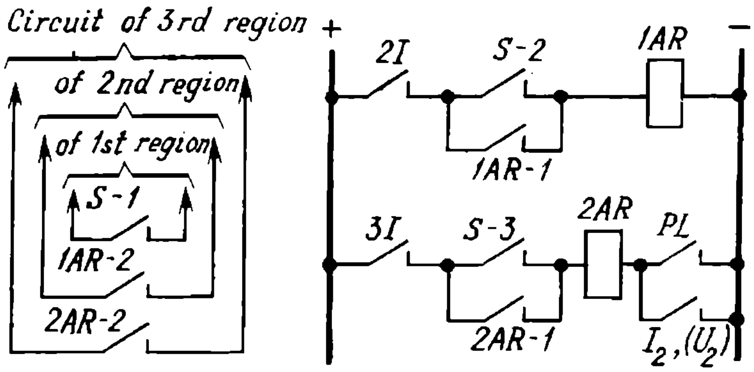


Fig. 4-49. Connection of phase limiter, swing and overload blocking circuit for three-stage distance protection
S — swing blocking contact; *2I* and *3I* — contacts of elements measuring impedances of the second and third regions of distance protection; *1AR* and *2AR* — auxiliary relays; *PL* — contacts of phase limiter; I_2, (U_2) — contacts of backward-sequence current (voltage) relay.

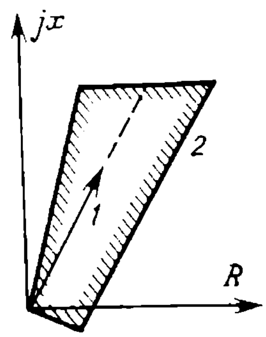


Fig. 4-50. Composite (shaped) characteristics of directional impedance relay
1 — characteristic of protected line with a resistor; *2* — relay characteristic.

by an angle not greater than 30 degrees or if there are unbalanced electrical quantities. Such conditions result from short circuits and are not present with balanced overloads.

The use of semiconductor devices in relaying protection and automatic control engineering has made it possible to design a distance protection starting element with a shaped characteristic (Fig. 4-50)[4-8]. This element combines in one apparatus a relay which functions in conformity with direction and phase limiters. It has a limited working area on the complex plane.

The use of devices responding to backward-sequence components at a widely unbalanced load, presence of upper-harmonic components in current and voltage and at large frequency variations in the power system. In recent years a.c. single-phase electric traction finds wide applications. Nonuniform loading of separate phases in a three-phase supply circuit manifests itself mainly in unbranched long electrical circuits with intermediate traction substations. The largest load variations occur when electric locomotives pulling heavy trains start to move.

In the absence of short circuits, unbalanced loads cause backward-sequence components of the electrical quantities accepted by the filter and the result may be an undesired start of the devices responding to the current or voltage backward-sequence components. To ensure proper operation of such devices with large load current variations, several methods have been developed.

First method. Operation of the blocking devices responding to the appearance of backward-sequence components of the electrical quantities is permitted only upon operation of the starting elements of the protection being blocked, which function from a drop in the impedance or in the interphase voltage (or forward sequence). The operation of such elements

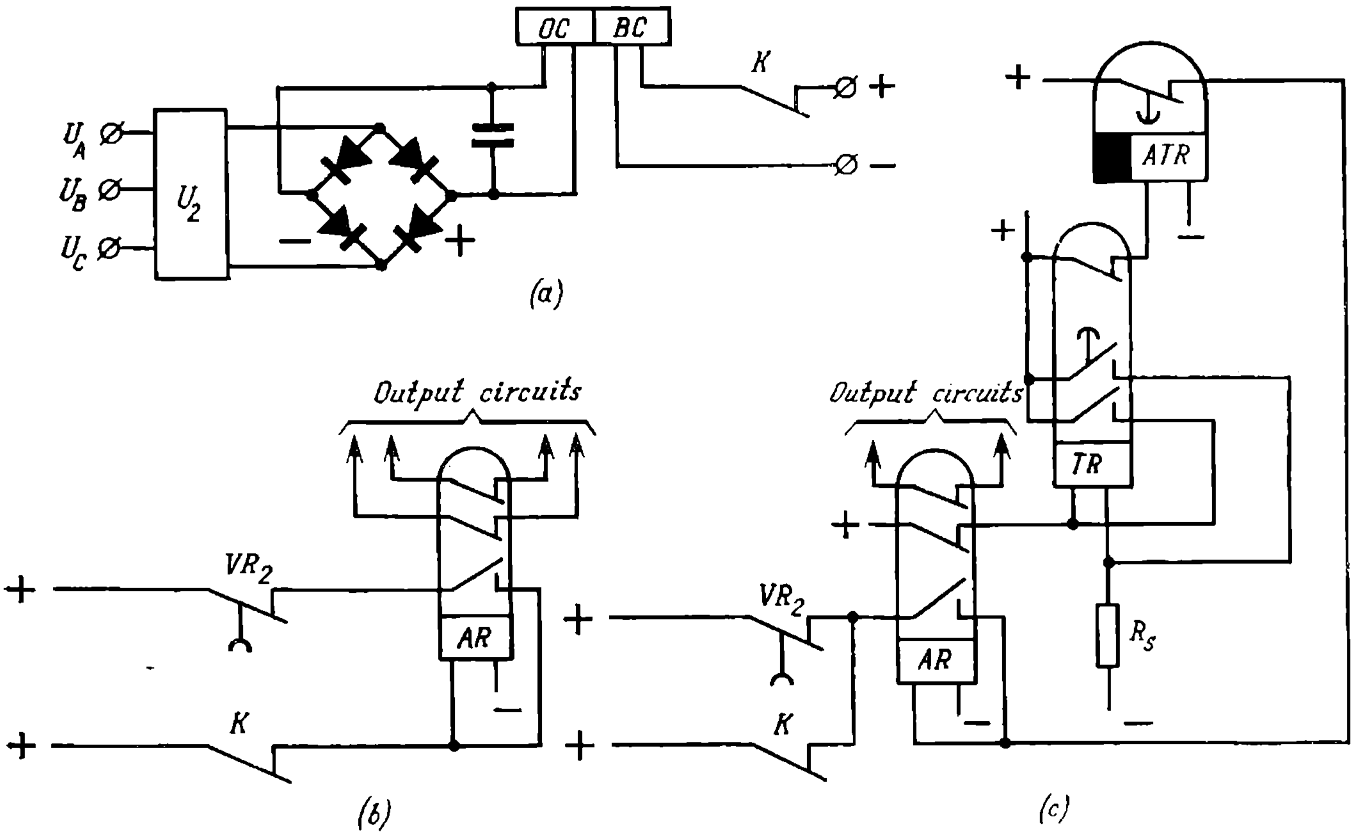


Fig. 4-51. Starting circuit of devices responding to backward-sequence components with prohibition when blocked protection is inoperative

(a) with polarized relay; (*b*) with instantaneous relay; (c) with time reset; *K* — high-speed relay contact closed when protection is inoperative

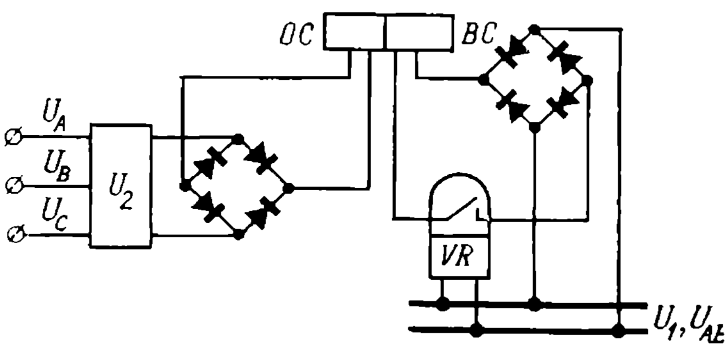


Fig. 4-52. Connection of output relay responding to backward-sequence components, with interphase or forward-sequence voltage braking

and the appearance of backward-sequence components are characteristic of a short circuit. No simultaneous operation of these devices (i.e., appearance of two qualities) takes place in the case of asymmetry due to unbalanced phase loading, unless there is a short circuit.

The schematic diagrams are shown in Figs. 4-51 and 4-52.

Figure 4-53 illustrates a circuit with interphase voltage braking. For curves showing the pick-up voltage versus the braking voltage value see Fig. 4-54.

Second method. In practice the unwanted operation of devices responding to backward-sequence components in networks supplying electric traction systems can be prevented in most cases by the use of an upper (mainly the fifth) harmonic filter at the output of the

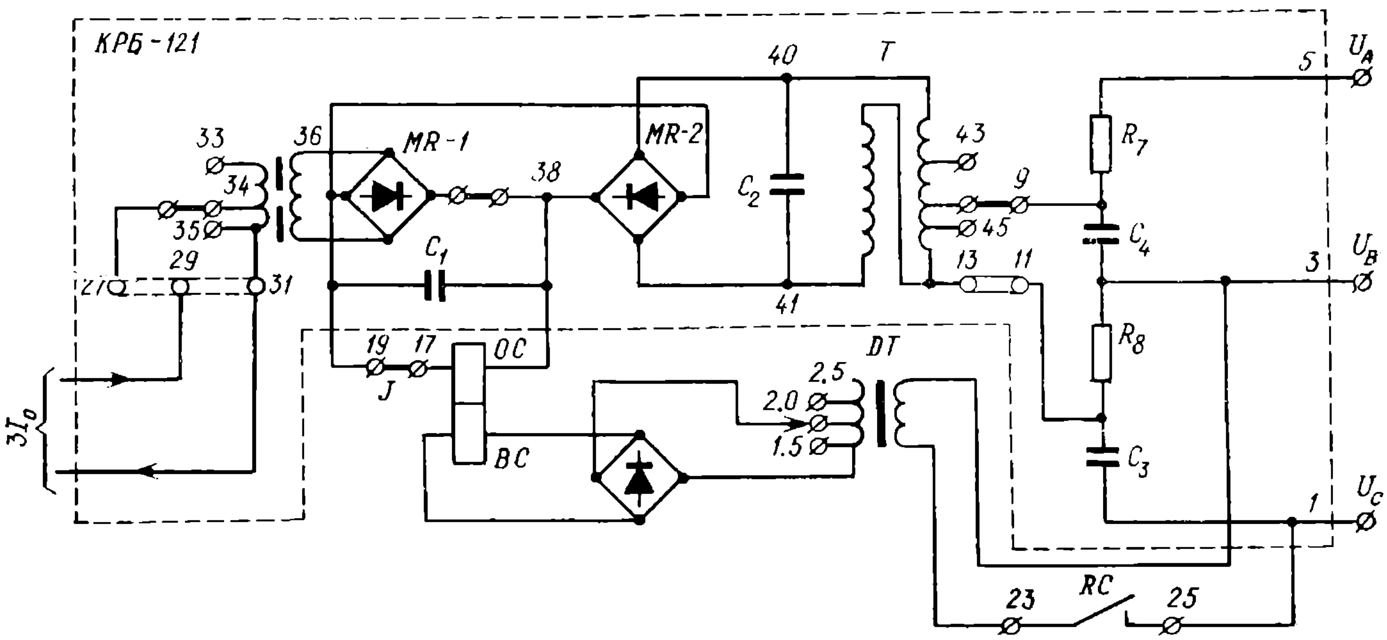


Fig. 4-53. Blocking circuit with voltage braking based on relay КРБ-121 (auxiliary circuits are contained within the dashed line)

RC — relay contact to completely remove voltage braking; *BC* and *OC* — braking and operating coils of output polarized relay (w_{OC}=8,800 turns of ПЭЛ-0.1 wire; R=730 Ohm; w_{BC} = 4,200 turns of ПЭЛ-0.1 wire; R = 600 Ohm); *DT*— decoupling transformer (w_1 = =3,000 turns of ПЭЛ-0.15 wire; w_2 = 300 turns of ПЭЛ-0.2 wire; taps from the 135th and 212nd turns)

backward-sequence filter (Fig. 4-55). These harmonics appear in the primary current and voltage due to the influence of rectifying units installed at the stationary step-down substations (like those for d.c. electric traction, on electrical locomotives, or in workshops).

An upper harmonics filter at the output of the backward-sequence filter adds to the sensitivity of the swing blocking device as it decreases the unbalanced currents and voltages at the output of the backward-sequence filters. The unbalanced currents and voltages occur due to disturbances to the sinusoidal nature of the circuit.

Third method. This makes it possible to reduce the unbalanced load influence on the operation of the blocking devices responding to the appearance of backward-sequence electrical quantities and the starting relay to be connected to the backward-sequence filter via a differentiating network. In this case the starting element of the blocking device responds to the rate of changes in the absolute values of the backward-sequence electrical quantities. Under short-circuit conditions this rate is much different from that under the normal electric traction conditions. The method was proposed and developed at "Irkutskenergo" by engineer V.P. Kletskiy. At the All-Union Scientific Research Institute of Power Engineering and Electrification A.I. Leviush proposed that the starting element of the blocking device be connected through a unit responsive to the rate of changes in the spatial position of the vectors

of backward-sequence current or voltage. This feature answers better the changes in backward-sequence electrical quantities at short circuits from their normal operating state.

The use of devices responsive to the appearance of backward-sequence components with voltage braking or with prohibition when the starting elements of the main protection system are not operating eliminates unwanted actions at short circuits in the contact wire circuit using single-phase alternating current. At the beginning of the electric traction service such short circuits are frequent, which often causes operation of the ordinary blocking devices due to swings. The devices in question may also be applied to those parts of the power system with large-power hydroelectric stations which allow for an excessive increase in frequency when isolating transmission lines connecting the hydroelectric stations with the receiving part of the power system. The balanced components filters though having improved frequency characteristics lose their accuracy when the frequency increases to 53 Hz or more and may cause operation of the sensing unit with resultant malfunction of the usual type device. The use of voltage braking or operation prohibition from the protection starting elements eliminates this defect. In addition, it becomes possible to isolate surges from lightning arresters and switching operations on many sections of the power transmission system.

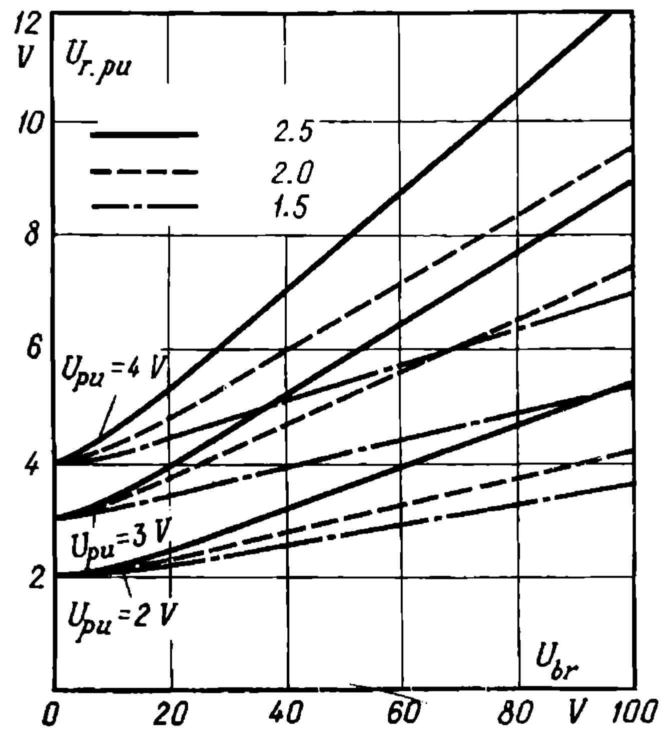


Fig. 4-54. Braking characteristics of device employing circuit shown in Fig. 4-53

With devices responding to backward-sequence currents braking by the current flowing in one of the phase conductors is sometimes used. The purpose of this type device is to

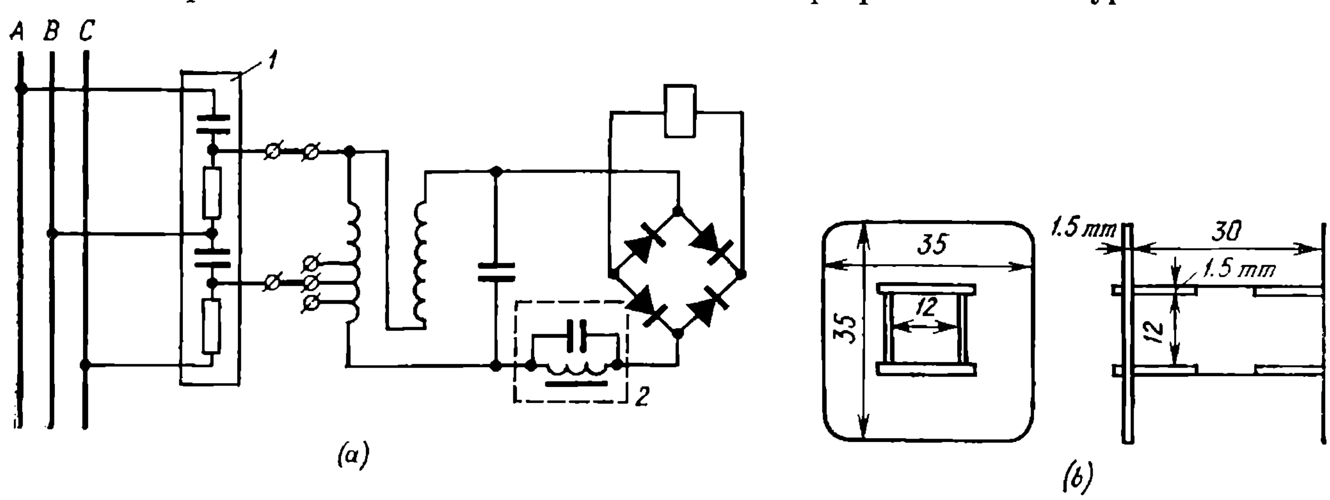


Fig. 4-55. 5th harmonic filter

(a) connection of filter to distance protection circuit; 1 — filter of backward-sequence voltage; 2 — filter of upper harmonics (reactance coil: w = 1,700 turns of ПЭЛ-0.35 mm wire; steel ХВП 12 × 12 mm; 2-mm air gap; C = 0.5 μF; U_l= 200 V); (b) coil form

prevent the likelihood of misoperation due to asymmetry, caused by increased unbalanced currents in the instrument current transformers during asynchronous operation with a fai-

rly large equalizing current. Connected to the transformers is the backward-sequence filter.

Unlike voltage braking, phase current braking desensitizes the performance of the starting element at short circuits, in particular at three-phase faults at which backward-sequence components instantly appear. To improve the sensitivity of such devices and prevent their failure at three-phase short circuits, it is good practice to place an inertia element (a reactance coil, for instance) into the circuit of the coil braking the output relay and carrying the phase current. This element decreases or fully eliminates the braking effect during a short circuit and realizes it at swing currents smoothly varying in time.

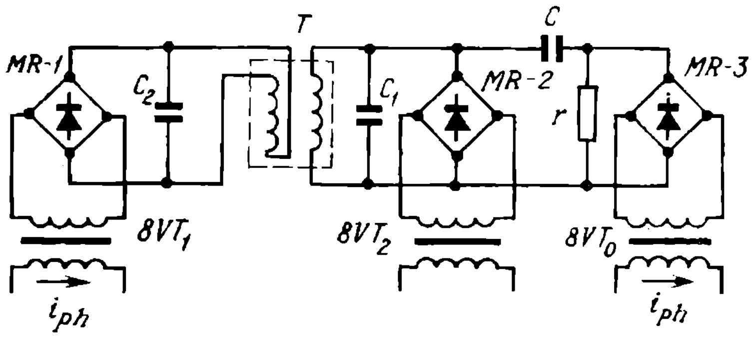


Fig. 4-56. A.C. circuits of device KPБ-122 supplemented with *R—C* differentiating network

To improve the response to three-phase short circuits of a blocking device which has phase current braking and responds to a backward-sequence current, it may be supplemented by the start from a unit responding to the rate of phase current change (Fig. 4-56) [4-9].

4-8. Conclusions

1. Stable operation of power systems is feasible providing they are furnished with an assemblage of automatic devices that increase the transmitting capacity of tie lines, improve the stability of generators, prevent, localize and clear emergencies.

2. To increase parallel operation stability of synchronous generators, apart from the use of automatic excitation controls, the rapid clearing of short circuits, quick unloading of the tie lines and emergency deceleration of the generators are also highly important.

3. Rapid unloading of the tie lines is best accomplished by automatically tripping the generators at the generating station (in particular at a hydroelectric station). The number of machines being disconnected is dependent upon the fault severity and the prefault and afterfault operation.

4. Automatic devices allowing the generating station to be unloaded without tripping the generators are in wide use. Classed with these devices are units regulating and limiting power flows and devices rapidly decelerating (rapid unloading) steam turbines.

5. Unloading the tie lines by disconnecting the consumers at the receiving part of the power system is permitted for a limited number of consumers who allow for short-time interruptions to the power supply.

6. The elements revealing the nature of a fault may be different combinations of current, voltage, impedance and power relays.

7. Remote tripping devices are used to quickly transfer the information about a fault from distant substations to the sending or receiving ends.

The operating time of the high-speed remote tripping system ranges from three to four cycles (periods).

8. To prevent prolonged asynchronous operation, use is made of automatic sectionalizing devices. Various designs are available.

9. The function of certain relaying protection devices is to ensure the desired speed of clearing short circuits and allow no misoperations during synchronous swings and overloads. Appropriate systems of blocking and starting elements are developed in the USSR which prevent malfunctions of the protection system.

10. Automatic sectionalizing devices responding to increased frequency are used to isolate thermal power stations from powerful hydroelectric ones in the case of a sudden frequency increase at the hydroelectric stations after disconnection of the tie lines from the power receiving system. These automatic devices are very important as they prevent damage to the thermal unit (the turbine and generator) when the generator starts motoring with resultant overspeeding.

4-9. Review Questions

1. Using equation (4-13), determine the time taken to trip a three-phase short circuit on a line running directly from the tie link between a power station and a power system when the relative angle between the emf vectors of the power station and system is increased by not more than 60 degrees relative to the normal value.

Make the calculations by supposing that the output of the power station is 70 per cent of the nominal output and with a three-phase short circuit after this power is thrown off, the generator rotors uniformly accelerate. The inertia constant of the generator-turbine units T_{in} is 10 s. The power of the power system is infinitely greater than the power of the station.

Solution. The tripping time equals

$$60=\frac{9,000}{10}\cdot 0.7t^2, \text{ hence } t=0.31 \text{ s}$$

2. Why is the rapid clearing of short circuits considered as a means of improving the transient stability of a power system?
3. Why, from the point of view of maintaining the stability of the generators operating in parallel, do three-phase short circuits require more rapid clearing than single-phase faults?
4. Describe the principles underlying the detecting elements of the devices responding to the value of angle δ between the emf vectors of generators operating in parallel.
5. Describe the principles underlying deceleration of steam turbines by short-time interruption in the steam admission to the turbine.
6. What is the purpose of the quick-acting distance tripping among the measures to improve the stability of power systems operating in parallel?
7. What are the principles underlying the quick-acting distance tripped devices?
8. Explain why a slowly operating protection under asynchronous conditions may fail to clear a short circuit.
9. Describe the electric centre of a power system. How do the electrical quantities change at the electric centre when the stability is disturbed?
10. How is the maximum equalizing current in a transmission line between a generating station and a power system determined?
11. What are the operating principles of phase limiters and how are they made? How is the arc resistance accounted for in the operating characteristic of a phase limiter?

12. What are the principles underlying the blocking devices preventing the operation of relaying devices protecting against load currents and loss of synchronism (the operating principle of the swing blocking devices)?

13. What are the principles and the areas of application of devices used for automatic division of a power system into balanced load sections to prevent loss of synchronism?

14. What are the principles of automatic sectionalizing devices responding to asynchronous operation and not to short circuits?

15. What are the principles of joint operation of automatic sectionalizing devices responding to asynchronous operation with automatic reclosure devices?

16. What is the purpose of sectionalizing devices, employing an overfrequency relay, which are installed on the tie link between thermal power and hydroelectric stations?

Chapter Five

AUTOMATIC FREQUENCY CONTROL

5-1. Purpose and Specific Features of Automatic Frequency Control (AFC)

Under steady-state conditions in a power system the power output of the generators (P_g) is always equal to the power consumed by the loads (P_l)

$$P_g = P_l \tag{5-1}$$

Any failure to meet conditions (5-1), i.e., in the case of a deficiency in the generated power (due to, for example, switching out some of the generators) or the excess in the power (caused by the tripping of some loads) may bring about unbalance between the powers being generated and consumed

$$\Delta P = P_g - P_l \tag{5-2}$$

This unbalance affects the speed of all the machines in the power system (generators and motors), it becomes less with a negative value of ΔP or more with a positive value of ΔP.

Maintenance of the nominal frequency is assured by frequency and power regulators which act on the water (or steam) inlet to the turbines, thus effecting condition (5-1) in conformity with the adopted regulation procedure.

By means of the frequency and power regulators the active power deficit may be eliminated when there is a mobile "hot" energy reserve available, i.e., if before the fault the generator turbines were not completely loaded and their speed governors do not limit the admission of steam or water. If such power reserve is not available the resultant deficit ΔP causes the machines to decelerate.

With lowered rotational speed, i.e., with a decreased frequency, the initial power deficit also decreases, since the output and power demands of the mechanisms decrease. For example, the output of blowers is proportional to the square of the frequency and the output of a number of pumps, to the third power of the frequency. The frequency reducing process continues until ΔP becomes zero, i.e., until at the new attained (final) frequency f_{fin} the generator output $P_{g\ f_{fin}}$ equals the power consumed by the loads ($P_{l\ fin}$).

Where no power reserve is available, the magnitude by which the frequency is reduced

$$\Delta f_{att} = f_{in} - f_{fin} \tag{5-3}$$

and the initial power deficit ΔP has the following relationship

$$\Delta P\,\% = K \Delta f_{att}\,\% \tag{5-4}$$

where

$$\Delta P\,\% = \frac{P_g - P_l}{P_l}\,100 \tag{5-5}$$

and

$$\Delta f_{att}\,\% = \frac{f_{in} - f_{fin}}{f_{in}}\,100 \tag{5-6}$$

The symbol K is called the load frequency regulating effect. It characterizes the changes in the power drawn by the consumers including the losses in the supply circuits caused by frequency variations in the power system. The value of the coefficient K is dependent on the load parameters and the voltage drop in the power system units as the frequency lowers. The K value also varies with the time of day, it is different on working days and holidays and depends upon the yearly seasons. Tests show that the value of the coefficient K ranges from 1 to 3.5. Its mean value is 2 to 2.5.

From the relationship (5-4) it is possible to determine the value the frequency will attain with a power deficit of $\Delta P\%$, when $f_{in} = 50$ Hz and $K = 2$

$$\Delta f_{att}\,\mathrm{Hz} = 0.5\,\frac{\Delta P\,\%}{K} = 0.25\,(\Delta P\,\%) \tag{5-7}$$

The frequency changes from the f_{in} value to the f_{fin} value gradually, rather than instantaneously, at a certain time constant dictated by the inertia of the rotating mass of the power system (parts of the turbines, generators, motors and mechanisms) and by the regulating effect K of the load.

The frequency varies in time approximately exponentially. When the frequency decreases from f_1 to f_2

$$f_2 = f_1 - \Delta f_{att}\,(1 - e^{-t/T_f}) \tag{5-8}$$

and when the frequency (until the frequency and power regulators start operating) increases from f_1 to f_2

$$f_2 = f_1 + \Delta f_{att}\,(1 - e^{-t/T_f}) \tag{5-9}$$

Thus

$$\Delta f_t = \pm\,\Delta f_{att}\,(1 - e^{-t/T_f}) \tag{5-10}$$

The time constant T_f can be roughly determined by the expression

$$T_f \approx \frac{T_{sys.\,iner}}{K} \tag{5-11}$$

where $T_{sys.\,iner}$ is the inertia constant of the power system.

Since the $T_{sys.\,iner}$ equals 10 to 16 s, T_f is about 5 to 8 s. Smaller values of $T_{sys.\,iner}$ correspond to parts of the power system where power units rated at 200-300 MW and greater preponderate.

Power system operation at a lower frequency than that specified by the State Standard [5-1] affects the quality of power supply and is not allowed because of the following:

(a) When operating at frequencies below 49.5 Hz, some types of steam turbines undergo excessive vibration in certain turbine rotor stages with resultant metal fatigue and blade failures.

(b) When the frequency falls below 49 Hz, the turbine regulating devices fully open and the generating units become completely loaded. A further decrease in frequency reduces the efficiency of the auxiliary mechanisms at thermal power stations, especially feed pumps. The result in the case of prolonged operation at a lowered frequency is a drop in the generated output and a further loss of power. The decrease in power system frequency may assume an avalanche nature which can stop the power stations for a prolonged outage.

(c) As the frequency decreases, the generator exciters lose their speed and the generator emf falls, the voltage in the power system units drops. This brings the danger of a "voltage avalanche" and disconnection of the consumers.

A frequency avalanche drop aggravated by a voltage avalanche drop causes a grave breakdown in the power system and a complete stoppage of the paralleled stations or division of the power system into separately operating sections with interruptions to the power supply of many consumers.

The function of the automatic frequency control (AFC) is to prevent the power system frequency from approaching a critical value, when a loss of active power occurs, by disconnecting part of the loads thereby keeping the power stations and their auxiliaries operative. In this case the power supply to the majority of consumers suffers no interruption and the supply to the disconnected loads can be restored within a fairly short period of time.

When the automatic frequency control is not available or insufficient, the consumers will be disconnected as well. However, due to stoppage of the power stations and loss of their auxiliary services, the restoration of power to the consumers will take much time. Disconnection of the consumers is accomplished by the AFC devices so that the frequency never drops below 45 Hz, operation at a frequency less than 47 Hz does not exceed 20 s and at 48.5 Hz, 50 s[5-2].

Moreover, AFC must be designed so that no unnecessary tripping (overregulation) occurs and after the action of AFC frequency does not exceed the rated value of 50 Hz. After the AFC device has operated, the frequency may be somewhat below the rated value, i.e., within 49.0 to 49.5 Hz and it is raised to the rated value by the operator.

If during frequency transition from f_{in} to f_{fin} which is caused by a loss in active power, a group of AFC devices operating at the f_a setting (Fig. 5-1) disconnect the load P_1 to be tripped first, the initial value of the power loss will decrease and become equal to

$$\Delta P_1 = \Delta P - P_1 \tag{5-12}$$

The new final value of frequency corresponds to ΔP_1

$$f_{1\,fin} = f_{in} - \Delta f_{1\,att} \tag{5-13}$$

where

$$\Delta F_{1\,att} = 0.5\,\frac{\Delta P_1\,\%}{K}\ \text{Hz}$$

(the initial frequency f_{in} is supposed to be 50 Hz).

After point a (Fig. 5-1) the frequency follows curve *2* rather than curve *1*. The equation of curve *2* may be approximately written as

$$f_{ab} = f_a - (f_a - f_{1\,fin})(1 - e^{-t/T_f}) \tag{5-14}$$

If at the frequency f_b another group of the AFC devices operates, the power loss will decrease again. The process of further frequency changing proceeds similarly. If after operation of the AFC devices the generated power exceeds

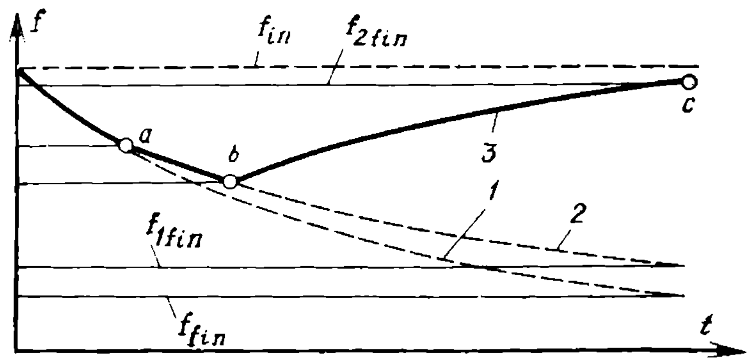


Fig. 5-1. Frequency changes with power deficit and after it is eliminated by AFC devices

the power drawn by the load remaining in operation the power system frequency will begin to increase. If such a process occurs at the instant corresponding to point b after the operation of an AFC group, the final frequency value of $f_{2\,fin}$ will exceed the frequency f_b and the power system frequency will start to restore itself (curve *3*).

The approximate equation of curve *3* is

$$f_{bc} = f_b + (f_{2\,fin} - f_b)(1 - e^{-t/T_f}) \tag{5-15}$$

The frequency time variation during the operation of the AFC devices can be found by using the approximate value of expression (5-10).

Since in the region of small values of t

$$e^{-t/T_f} \approx (1 - t/T_f) \tag{5-16}$$

expression (5-10) may be presented in the form

$$\Delta f_t \approx \pm \left(\Delta f_{att} \frac{t}{T_f}\right) \tag{5-17}$$

(the minus sign stands for a decrease in the frequency and the plus sign, for an increase).

Hence, when plotting the relation $f = \varphi(t)$, straight lines may be substituted for the curve sections (Fig. 5-2). The greater the number of AFC groups and the more rapidly their function, the less the error.

The letters, a, b and c in Fig. 5-2 stand for the characteristic points of the frequency changing process in time which are obtained by rough plotting. The points marked a', b' and c' are plotted more accurately with the use of re-

lationship (5-10). This accounts for the fact that the decay of the exponent determining the law of frequency time variation takes place when $t \doteq 3T_f$.

The AFC devices came into use in the USSR more than 25 years ago, when many of the Soviet power systems operated separately. In the first period the power systems were short of relaying equipment but at that particular time the

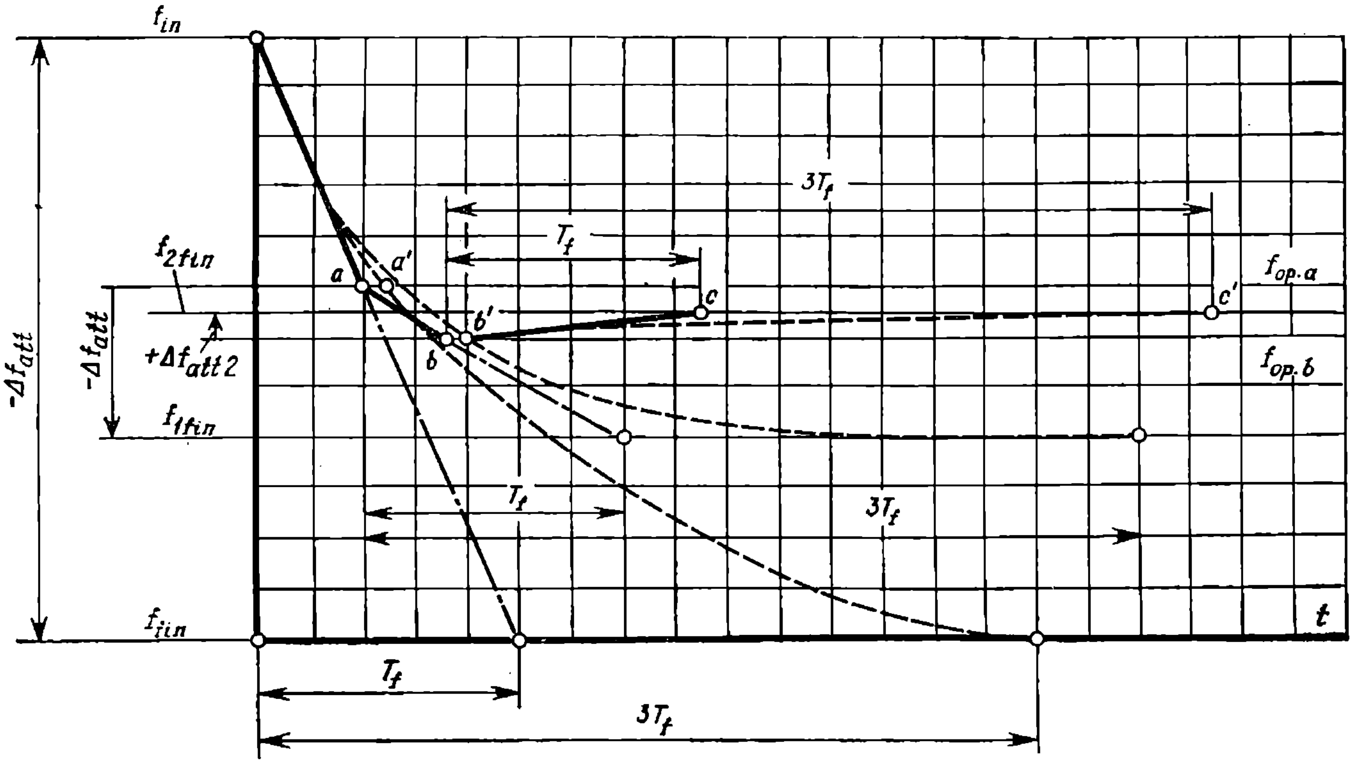


Fig. 5-2. Frequency changes in the case of power deficit (approximate plotting)

AFC devices were given priority in order to avoid serious faults. The AFC devices had to be used economically, and small quantities were used to selectively control large power loads.

With such frequency control, excessive power to the consumers has often been switched off or insufficient disconnection took place when the frequency was held at a value of 47.0 to 47.5 Hz. Later the basic groups of AFC devices were supplemented with others to prevent the frequency holding. This somewhat improved the service, but the faults were not completely eliminated.

5-2. Modern Principles of AFC

Modern integrated high-power systems with long extension lines are particularly noted for a great variety of possible emergencies. A deficit in generated power may occur in one small area, effect a group of power systems, involve all the power systems, etc. It may differ in the initial value, in its area of spread and in dynamics of progress. It is necessary to consider the demands according to season, days (working days, days off and holidays), the time of day and

repair work. Thus, in the case of an integrated powered system the task of determining the maximum rated power deficiency becomes, to a great extent, a probability problem.

The following formulates the principles of the modern AFC:

1. The AFC system must eliminate all of the many possible faults regardless of the real power loss, its spread over the system and its growth rate.

2. Amount of the load being tripped must always be close to the power loss, i.e., the AFC device must adjust itself to this value.

For the AFC design principles see references[5-2, 5-3].

There are three categories of frequency control:

1st category, AFC-I is a high-speed control having different frequency settings. It is designed to hold up the frequency decrease.

2nd category, AFC-II has a common frequency setting and different time settings. It is used to raise the frequency after operation of AFC-I, and also to prevent frequency holding and slow frequency loss, when the generated power is slowly reduced in an emergency.

3rd category, an auxiliary one which provides, when possible, selective operation. It is designed to facilitate the load tripping and increase its volume at heavy reductions (45% and more) in generated power caused by separating an area from the main supply sources.

The frequency setting of the AFC-I groups ranges from 48.5 to 46.5 Hz. Operation of the groups is almost uniformly distributed within this range, the minimum frequency steps being 0.1 Hz (as dictated by the accuracy of the instruments used for adjustment of the frequency relays such as measuring instruments and frequency oscillators).

The time settings of the AFC-I devices must be as small as practicable. Their value is determined by the requirements to prevent malfunction during transient processes in the voltage circuits in case of deenergizing. The operating time of the AFC-I devices with relays ИВЧ-011 and ИВЧ-3 is 0.25 to 0.5 s and with transistorized relays РЧ-1, 0.1 to 0.15 s. All the groups of the AFC-II devices have the same operating frequency of 48.5 Hz, but their time settings vary with various units from 5 to 40 s and may run up to 90 s in power systems including hydroelectric stations which may be mobilized in the case of a breakdown affecting the frequency. Adjacent groups of the AFC-II devices operate at 3 to 5 s time intervals.

When the number of AFC-I and AFC-II operating groups is large (10 to 20 groups in each frequency control category) with small frequency operating steps (the AFC-I units) and small operating time intervals (the AFC-II units), the operation of adjacent groups may not be selective because of relay setting scatter.

The power capacity of loads connected to the AFC-I devices in each area of a power system of the power pool must be equal to the maximum value ΔP_{max} of the power loss being determined by considering possible emergency situations and taken with a certain margin

$$P_{AFC\text{-}I} = k_s \Delta P_{max}$$

The safety factor k_s is taken as 1.05 owing to the stochastic character of the loss onset (when determining ΔP_{max} the spinning reserve of thermal stations is not included, this also adds to the safety contained in the calculation).

Connected to the AFC-II devices are loads the total power of which is not less than 0.4-0.5 of $\Delta P_{AFC\text{-}I}$.

With both categories of frequency control, the connected power is distributed among the operating groups of each category almost uniformly, which with a large number of operating groups provides a flexible frequency control system without the risk of unwanted trippings. When distributing the loads between the AFC groups, the importance of the load being connected must be taken into consideration. Loads of greater importance should be connected to the AFC-I groups having lower frequency settings and to the AFC-II groups with higher time settings.

The further stage in the development of the AFC system is to match the operation of both frequency control categories (AFC-I and AFC-II) for tripping the same loads; high- and low-speed starting of the AFC device is accomplished for tripping one and the same load. In this case the AFC-I groups having the lower frequency settings must be matched with the AFC-II groups more distant in time. In emergency situations such an AFC system arrangement ensures a better operating sequence of the frequency control groups with account of the importance of the loads being connected (this sequence may be disturbed when AFC-I and AFC-II are employed independently) and also decreases to some extent the AFC safety margin.

With a large number of AFC devices, they are installed directly at the consumers. This makes the monitoring of the automatic control devices by the power system difficult. To provide an operating margin it is advisable to install additional sets of AFC units on the feed lines running from the power system substations to the user's substations.

When the stability is disturbed and the frequency of the receiving system decreases during continuous loss of synchronism, disconnection of part of the loads from the AFC system may facilitate resynchronization of the grid system part which lacks power. The design technique of AFC for resynchronization is dealt with in reference [5-2].

When disconnecting a system deficit in power from the grid power system the AFC function may facilitate the operation of the ARC devices with a synchronism seizure on the intersystem tie line.

Auxiliary frequency control devices are used in the power system networks liable to heavy local power deficits resulting in a frequency drop to 45 Hz or less even after operation of AFC-I. This, as a rule, causes a large voltage drop, a circumstance should be taken into account when choosing the type of connection circuit for the frequency relay and the type of the relay.

The following are recommended as criteria for the use of auxiliary frequency control devices:

(a) Factors showing the appearance of local power deficit regardless of frequency change, i.e., tripping of a line or transformer with indication of the power flow and direction under the prefault conditions (or without the indica-

tion) and changes in the value of current or the value and direction of power flow in the line or transformer.

(b) Frequency changing rate.

(c) Drop in the forward-sequence voltage, if the loss of real power involves a considerable reactive power loss.

The frequency control must be as quick as practicable, the voltage control operation of the AFC system must be isolated against the duration of short circuits being cleared by the protective relaying system.

The use of automatic sectionalizing frequency-responsive controls employed as stand-by equipment for an auxiliary frequency control device or substituted for it is important. These controls separate some generators of the power station to supply its auxiliaries and isolate generators and individual stations carrying a roughly balanced load [5-5].

The automatic sectionalizing controls maintaining supply to the auxiliaries of thermal stations utilize two starting elements: one functions at 45 Hz within 0.5 s and the other at 47 Hz within 30 to 40 s. The automatic sectionalizing controls holding power supply to the most important consumers may have a frequency setting ranging from 46.5 to 47.5 Hz and an operating time of 1 s or less. If this is the case, their operation may not be selective relative to the AFC devices of the power system.

When the AFC devices are used it must be remembered that the frequency relays may respond not only to drops in the frequency due to a lack of power, but also to a number of other causes outlined below. An effective way of mitigating the effects produced by misoperation of the AFC devices is given by the use of an automatic load reclosure device which operates after restoring the frequency. Therefore the AFC devices must be combined with the frequency automatic load reclosure devices [5-2, 5-3].

In addition to the above-described AFC principles, frequency control may be accomplished by other methods. Let us consider some of these techniques.

AFC devices responsive to frequency change rate. Taking into account (5-4), expression (5-17) can be transformed into

$$\Delta P\,\% = \left(\frac{\Delta f_t\,\%}{t}\right) K T_f \tag{5-18}$$

It is seen from (5-18) and Fig. 5-2 that the rate at which the frequency changes at the beginning of disturbance is the criterion determining the relative value of the power loss. The higher the rate, the greater the relative value of power loss and the larger the load to be tripped.

At the same time, with the same relative power loss (i.e., with the same frequency changing rate), loads that differ in absolute value are to be connected from the AFC device when faults occur in areas, power systems or power pools having different power ratings. In this connection, the settings of such an AFC system are selected with difficulty and the system cannot be made self-adjusting. The AFC system may be built with combined starting responding both to the absolute value and to the rate of frequency drop.

It is good practice to utilize the rate factor of frequency decrease to additionally reduce the load in the areas where the frequency drop rate is far higher that at the power loss of the whole power system (see above). The rate factor of frequency decrease may be used also to fulfil AFC in small individual power systems.

AFC devices with time delay dependent on frequency. The operating principle of this type frequency control is as follows [5-4]. The AFC device picks up when the frequency drops to the pick-up setting. Starting from this moment, the pick-up settings of the frequency relay gradually increase with time. Thus, at heavy frequency drops which occur at a high rate and result from a heavy power loss, the AFC devices utilizing time-lag frequency relays will operate rapidly, i.e., like the AFC-I devices. When the power loss decreases, after tripping a part of the load and reducing the rate of frequency drop, the operating time of the AFC devices rises. These devices automatically follow the process of frequency changing and operate as the AFC-II category.

The AFC devices in which the time lag depends upon the frequency make it possible to accelerate the operation of the frequency control groups with an increase in the power loss and raise the frequency to values close to the rated. The use of time-lag frequency relays for arrangement of the AFC under consideration is yet outlined only in general terms. It is still required to develop appropriate equipment and techniques for choosing settings for such frequency controls and also to evaluate the compatibility of such a method with the AFC devices in service, etc.

AFC devices with control high-speed computer. Equipping the power system control departments with high-speed electronic computers, the assignment of control functions to these computers and the introduction of an automated control system allow the electronic computers to be used for automatic frequency control.

The power deficit may be determined by the computer according to the rate of the initial frequency change or by comparison of the generated and consumed powers in the given network of the power system. The computer may supply control pulses which trip certain consumers, change the AFC settings, etc., depending on the real power deficit, its location within the power system and the importance of consumers. Such an AFC system needs remote-control means.

5-3. Short-Time Drops of Frequency

Short-time drops in the terminal frequency of the measuring element employed by an AFC device may be due to the following reasons:

(a) When the busbar frequency of receiving substations drops because of the busbars being deenergized (for example, in the operating cycle of ARC and ACS devices). This is because the synchronous and asynchronous motors continue rotating due to inertia and maintain the voltage for some time while the frequency gradually decreases.

(b) When the frequency decreases with a loss of synchronism or synchronous swings because of voltage pulsations at a frequency other than normal.

(c) When the frequency decreases in a low-rated power system during short circuits as a result of an increase in active losses in the system elements.

(d) When the frequency drops for a short time due to sluggish operation of the hydraulic turbine speed governor if a spinning reserve is available.

Operation of the AFC devices at short-time drops of the frequency due to the above-mentioned causes is unwarranted even if the automatic load reclosure devices restore the power supply to the consumer. An interruption in the supply may halt a production process. For this reason it is advisable to use the means which can prevent unwarranted operation of the AFC devices. This chapter considers some of these means.

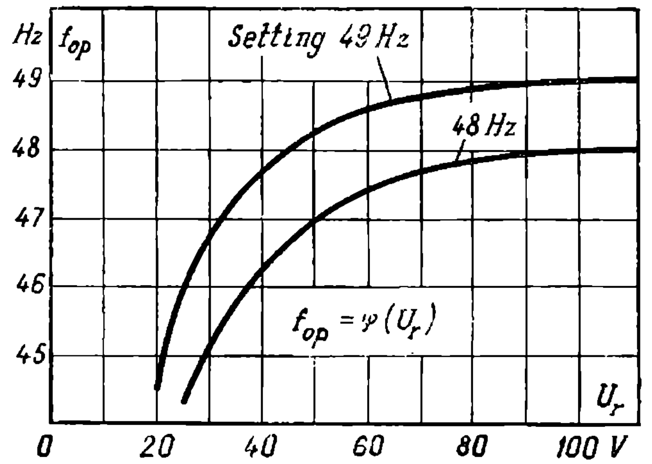


Fig. 5-3. Operating frequency of relay ИВЧ-011 versus voltage (experimental data)

Changes in the frequency of voltage held by asynchronous and synchronous loads after the substation is deenergized. When a power supply line or power transformer is disconnected, the busbar voltage of the receiving substation disappears, but not at once. Where asynchronous motors are used, the voltage drops to a value of 0.1 to 0.15 of U_n in 1.0 to 1.5 s. The process is prolonged (self-excitation takes place) if there are parallel-connected banks of capacitors in service. Synchronous motors and capacitors may hold a voltage with a decreasing frequency for a longer time, during several seconds.

Induction underfrequency relays ИВЧ-011 and ИВЧ-03 are ineffective when the voltage drops below 20-25 per cent of the rating (Fig. 5-3) and semiconductor underfrequency relays РЧ-I, below 5 to 10 per cent of the nominal value.

Under the conditions being considered several methods may be used to prevent unwanted operation of the AFC devices:

1. The substation loads may be connected to the AFC-II devices having a considerable operating time which exceeds the voltage decay time without using AFC-I devices.

2. The feed lines may be furnished with a device which blocks the AFC units with the aid of active power or current relays that break the operational circuit of the AFC unit after the line is disconnected and no load current flows in it. The use of a current relay is permitted if the minimum load current in the line exceeds the short-circuit current generated by the load when a short circuit occurs on the line near the busbars of the receiving substation.

Changes in the frequency during loss of synchronism. When a power system is pulled out of synchronism the frequency of the voltages at various parts of

the system becomes different. The areas lacking active power have the lowest frequency; areas with excess power have the highest frequency. As already mentioned, the AFC devices operating with a power deficit facilitate resynchronization. At the same time resynchronization may occur in certain cases without operation of AFC devices. Under such conditions, disconnection of loads by the AFC devices may prove to be unnecessary. Operation of an AFC device is not recommended when, in order to eliminate the loss of synchronism, the power system is quickly divided into sections with equal power balance between generation and load. Prolonged asynchronous operation when equalizing currents are flowing may also cause additional losses of real power and increase the number of loads tripped by the AFC devices.

The operation of AFC devices under asynchronous conditions is analyzed in special literature[5-6, 5-7].

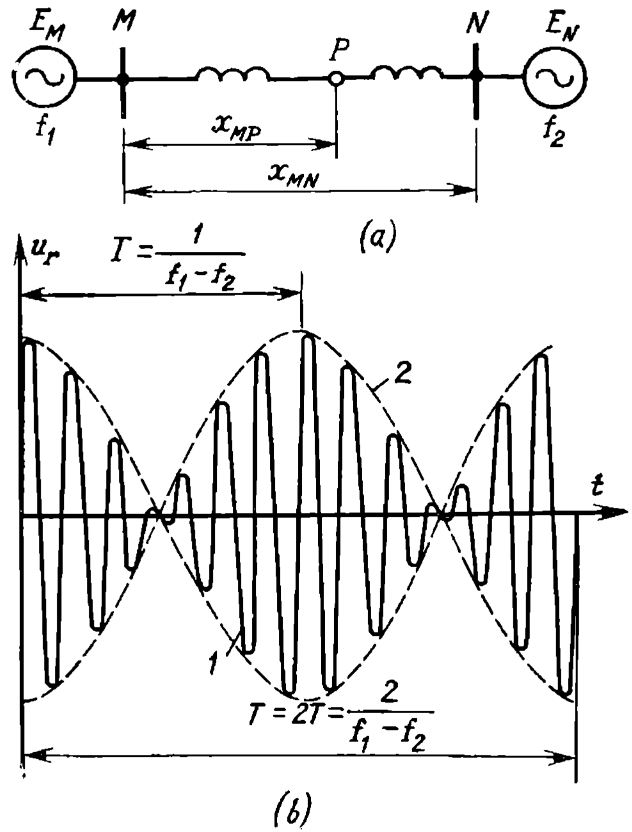


Fig. 5-4. Frequency variation in asynchronous operation

(a) elementary circuit; (b) electric centre voltage in asynchronous operation; 1 — carrier voltage; 2 — envelope of voltage instantaneous peaks

Let the power system M (Fig. 5-4a), whose emf

$$E_M = E_{M\,\max} \sin 2\pi f_1 t \qquad (5\text{-}19)$$

be out of synchronism relative to the station N whose emf

$$E_N = E_{N\,\max} \sin 2\pi f_2 t \qquad (5\text{-}20)$$

The relationship between the system and station frequencies is as follows

$$f_2 < f_1$$

The voltage at arbitrary point P

$$\dot{U}_P = \dot{E}_M - j\dot{I}_{eq} x_{MP} \qquad (5\text{-}21)$$

where I_{eq} is the equalizing current

$$I_{eq} = \frac{\dot{E}_M - \dot{E}_N}{jx_{MN}} \qquad (5\text{-}22)$$

Thus

$$\dot{U}_P = \dot{E}_M - (\dot{E}_M - \dot{E}_N)\frac{x_{MP}}{x_{MN}} = \left(1 - \frac{x_{MP}}{x_{MN}}\right)\dot{E}_M + \frac{x_{MP}}{x_{MN}}\dot{E}_N \qquad (5\text{-}23)$$

Generally, determining $U_P = f(t)$ is complicated[5-8]. To obtain a qualitative analysis, let $|\dot{E}_M| = |\dot{E}_N| = 1$. Taking into account (5-19) and (5-20),

we obtain

$$U_P=\left(1-\frac{x_{MP}}{x_{MN}}\right)\sin 2\pi f_1 t+\frac{x_{MP}}{x_{MN}}\sin 2\pi f_2 t \tag{5-24}$$

With $x_{MP}=0.5x_{MN}$ point P coincides with the electric centre. The electric centre voltage

$$U_K=\frac{1}{2}\sin 2\pi f_1 t+\frac{1}{2}\sin 2\pi f_2 t \tag{5-25}$$

or

$$U_K=\sin 2\pi\frac{f_1+f_2}{2}t\cos 2\pi\times\frac{f_1-f_2}{2}t \tag{5-26}$$

It follows from (5-26) that the frequency relay will respond to the frequency $\frac{f_1+f_2}{2}$, called the carrier frequency (Fig. 5-4*b*) [5-8].

Figure 5-5 shows the operating areas of an AFC device utilizing a frequency relay, type ИВЧ-011 (ИВЧ-3), and a time relay with settings $t_{TR}=0$ s, $t_{TR}=0.5$ s and $t_{TR}>1$ s. These characteristics are obtained experimentally [5-7].

The position of an AFC device in the elementary circuit in Fig. 5-4*a* is determined by the relationship U_1/U_2, where

$$U_1=E_M\left(1-\frac{x_{MP}}{x_{MN}}\right) \tag{5-27}$$

$$U_2=E_N\frac{x_{MP}}{x_{MN}} \tag{5-28}$$

The generators M and N are included in x_{MP} and x_{MN} respectively as transient reactances x'_d.

It is clear from the characteristic, that an increase in the time delay and a decrease in the frequency setting of the AFC devices reduce the areas of AFC possible operation during loss of synchronism.

Changes in the frequency in case of power inrush during short circuit [5-9]. Power inrush during a short circuit occurs due to an increase in the active losses when the short-circuit current flows.

The active power loss

$$\Delta P_{sc}=3I_{sc}^2R_{sc} \tag{5-29}$$

The three-phase short-circuit current

$$I_{sc}=\frac{U_{n.\,ph}}{\sqrt{x_{sc}^2+R^2}} \tag{5-30}$$

Hence

$$\Delta P_{sc}=3U_{n.\,ph}^2\frac{R_{sc}}{x_{sc}^2+R_{sc}^2} \tag{5-31}$$

where $U_{n.\,ph}$ = nominal phase voltage
x_{sc} = inductive reactance to the point of short circuit
R_{sc} = resistance to the point of short circuit

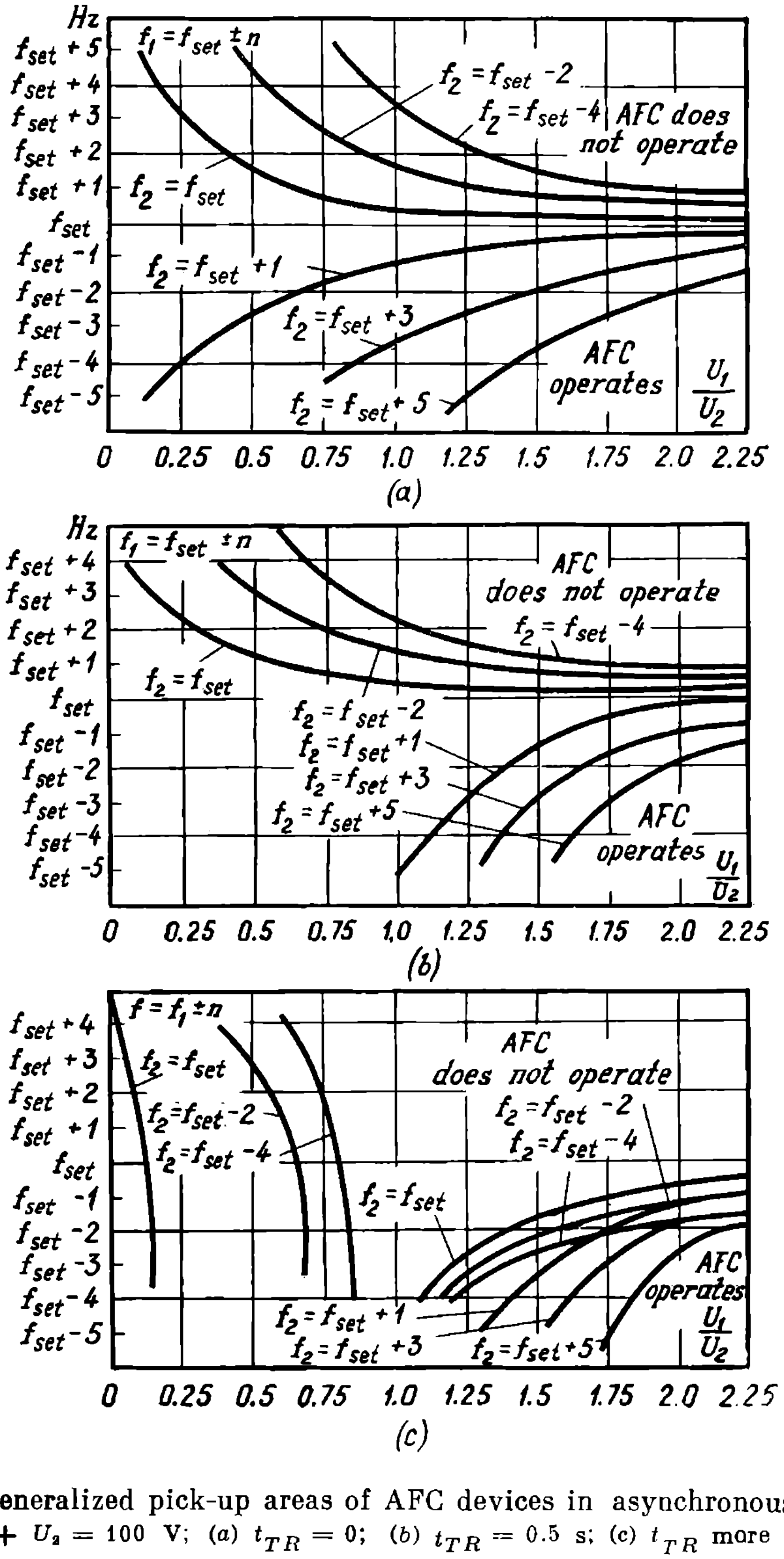


Fig. 5-5. Generalized pick-up areas of AFC devices in asynchronous operation $U = U_1 + U_2 = 100$ V; (*a*) $t_{TR} = 0$; (*b*) $t_{TR} = 0.5$ s; (c) t_{TR} more than 1 s

The maximum value of ΔP_{sc} is determined from the condition

$$\frac{\partial \Delta P_{sc}}{\partial R_{sc}}=0 \tag{5-32}$$

Thus

$$R_{sc}=x_{sc} \tag{5-33}$$

and

$$\Delta P_{sc\,\max}=\frac{3U^2_{n.\,ph}}{2}\,\frac{1}{x_{sc}} \tag{5-34}$$

If one takes into account that the short-circuit reactive power calculated when choosing the equipment

$$Q_{sc}=\frac{3U^2_{n.\,ph}}{x_{sc}} \tag{5-35}$$

then the maximum inrush in real power

$$(\Delta P_{sc\,\max}),\ \mathrm{kW}=(0.5Q_{sc}),\ \mathrm{kV\cdot A} \tag{5-36}$$

With short circuits dictating disconnection of the consumers or entailing heavy voltage drops across the unfaulted parts of the power system, the resulting power inrush will be obviously less and dependent on the amount of tripped power. More than that, in certain cases the power tripped may exceed the value of inrush. Power inrushes caused by short circuits should be taken into account with self-contained small-rated power systems (up to 500 MW) when damaged equipment cannot be rapidly tripped and in the presence of lines possessing high resistance (35 kV and less). Real power inrushes up to 50 to 70 MW have been encountered in power systems with short circuits. If a short circuit is quickly cleared the frequency has no time to drop to the value at which the first group of AFC devices functions. Therefore, in low rated power systems rapid clearing of faults is regarded as the basic measure to prevent the AFC devices operating.

The short-circuit clearing time in cable circuits equipped with reactors is of 2 to 3 s. Such periods are sufficient to decrease frequency to 47.5-48 Hz in power systems rated for 400 MW or less.

As mentioned above, the restoration of supply to the consumers after clearing a short circuit and raising the frequency in a power system is accomplished by the frequency automatic reclosure system (FARC).

Changes in the frequency due to sluggish operation of the speed governors of hydraulic turbines. When the ratio between the power demand and generation abruptly changes, the turbine speed governors have no time to make the required alterations to the water volume for the turbine. The result may be a decrease in the frequency of the power system in spite of the fact that the underloaded generators may have some reserve power. This was the cause of a frequency decrease to 48.5 Hz in 10 s and operation of the first groups of AFC-I devices.

It is again the FARC system that corrects the malfunction of the AFC-I devices. The action time of the AFC-II devices must be sufficient to adjust their operation when the frequency decreases because of the slow operation of the turbine speed governors.

5-4. Choice of Parameters of FARC Devices and Work of Operators

When a possibility occurs of restoring the power system frequency by mobilizing the output of hydroelectric stations or by rapid connection of tripped areas for parallel operation with the other part of the power system (through the use of FARC and ARC, for instance, with synchronism catchment), it is advisable to equip all stations having the AFC devices with the FARC units. The FARC units should be installed at the most important consumers connected to the last groups of the AFC devices and also at the consumers being tripped by the first groups of the AFC devices which are most liable to function at short-time small frequency drops. Besides, it is useful as well to use the FARC units on loads supplied from self-contained substations, i.e., those without personnel and remote-control devices.

Like the case with the AFC devices, the FARC units are used in several groups, their frequency settings ranging from 49.2 to 50 Hz. The initial time setting is 10 to 20 s. The final time setting may be different depending upon local power system conditions. Within a power system or an individual network the minimum time interval at which the adjacent FARC groups operate is about 5 s[5-2]. The load connected to the FARC devices is almost uniformly distributed between the groups.

The load reclosure sequence by the FARC devices is the reverse of that used when they are tripped by the AFC devices. To make the operating conditions for the sources of operational current easier, when a FARC group closes several switches, the latter are made to function in turn at 1-s intervals.

To prevent the frequency from decreasing repeatedly after the operation of the FARC devices (which may again result in functioning of the AFC system), these devices must be of single action, i.e., if after the operation of the FARC devices the power system frequency is lowered initially, the FARC devices will not function again after restoration of the frequency.

The use of the AFC and FARC devices does not free the attending personnel of responsibility for the proper operation of the power system. If an emergency situation arises that may result in a dangerous frequency drop (for example, at the hours of maximum demand), measures should have been taken before to limit the power consumption. If the operation of the AFC devices is ineffective the operators must take firm measures to prevent the frequency drop and its holding below 49.5 Hz.

The possibility of reconnecting loads tripped by the AFC devices to another power source by the automatic transfer units should be ruled out. At the same time, when recovering the frequency and eliminating the emergency situation responsible for a reduction in the frequency of a given area (for example, after the transmission lines are cut in), the power supply to the tripped loads must be reestablished as quickly as practicable.

5-5. AFC and FARC Circuits

The circuit of an AFC device without subsequent automatic reclosure is shown in Fig. 5-6. An underfrequency relay trips the breakers via an output auxiliary relay and a time relay. Simultaneously a prohibitive signal is fed

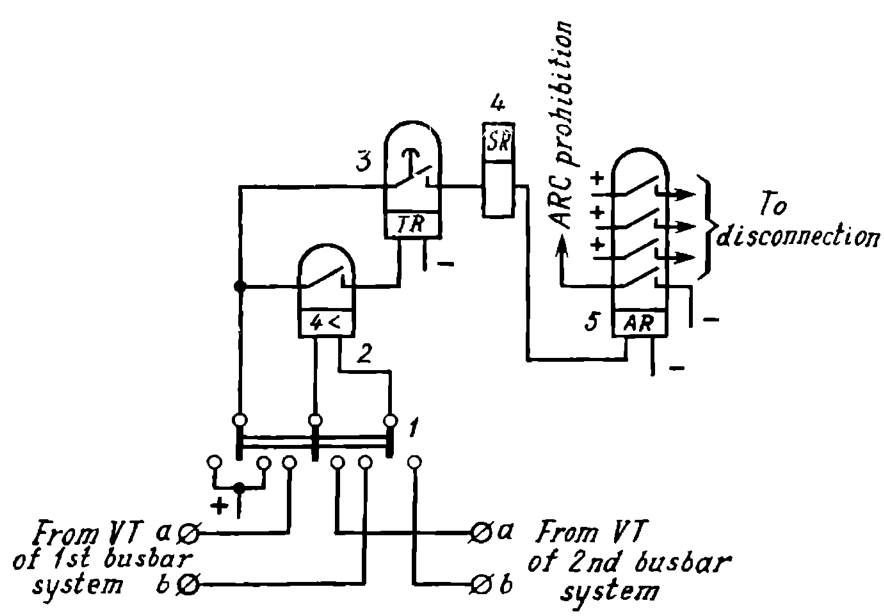


Fig. 5-6. AFC circuit with prohibiting operation of ARC device installed on connection

to the ARC devices which respond to the discrepancy and are installed on connections. These devices do not call for reclosure after the operation of the AFC device.

The underfrequency relay is connected to the voltage transformers through a knife switch 1 whose blades first make the voltage circuits and then the operative current circuit. The knife switch is opened in the reverse order. This prevents the time relay picking up when the supply of the frequency relay is changed from the voltage transformer of the first busbar system to the second one and vice versa.

The circuit diagrams of the AFC devices with a subsequent ARC after frequency recovery (by FARC) are illustrated in Figs. 5-7 and 5-8. The circuits are made to conform to the frequency relays, type ИВЧ-011 (ИВЧ-3) (Fig. 5-10).

Let us consider the diagram of the AFC device in Fig. 5-7. The underfrequency relay *FR* operates and closes the time relay *TR* whose contact *TR-2* switches on the auxiliary relays *1AR* and *3AR*. The relay *1AR* trips the breakers. On closing the contact *3AR-1*, the relay *3AR* changes the resistance connected in series with one of the coils of the frequency relay (the resistor is integral with the relay case) to change the frequency relay setting and vary the reset frequency of the relay. The contact *3AR-2* makes the circuit of relay *ATR* whose reset is delayed when the armature drops out. The circuit of relay *2AR* is opened by the contact *3AR-3*.

When the time relay *TR* is closed for a long period, its thermal stability is obtained by breaking the contact *TR-1* which introduces a current-limiting resistance. The time relay resets when the frequency is recovered and the frequency relay contact opens. The relays *1AR* and *3AR* become deenergized.

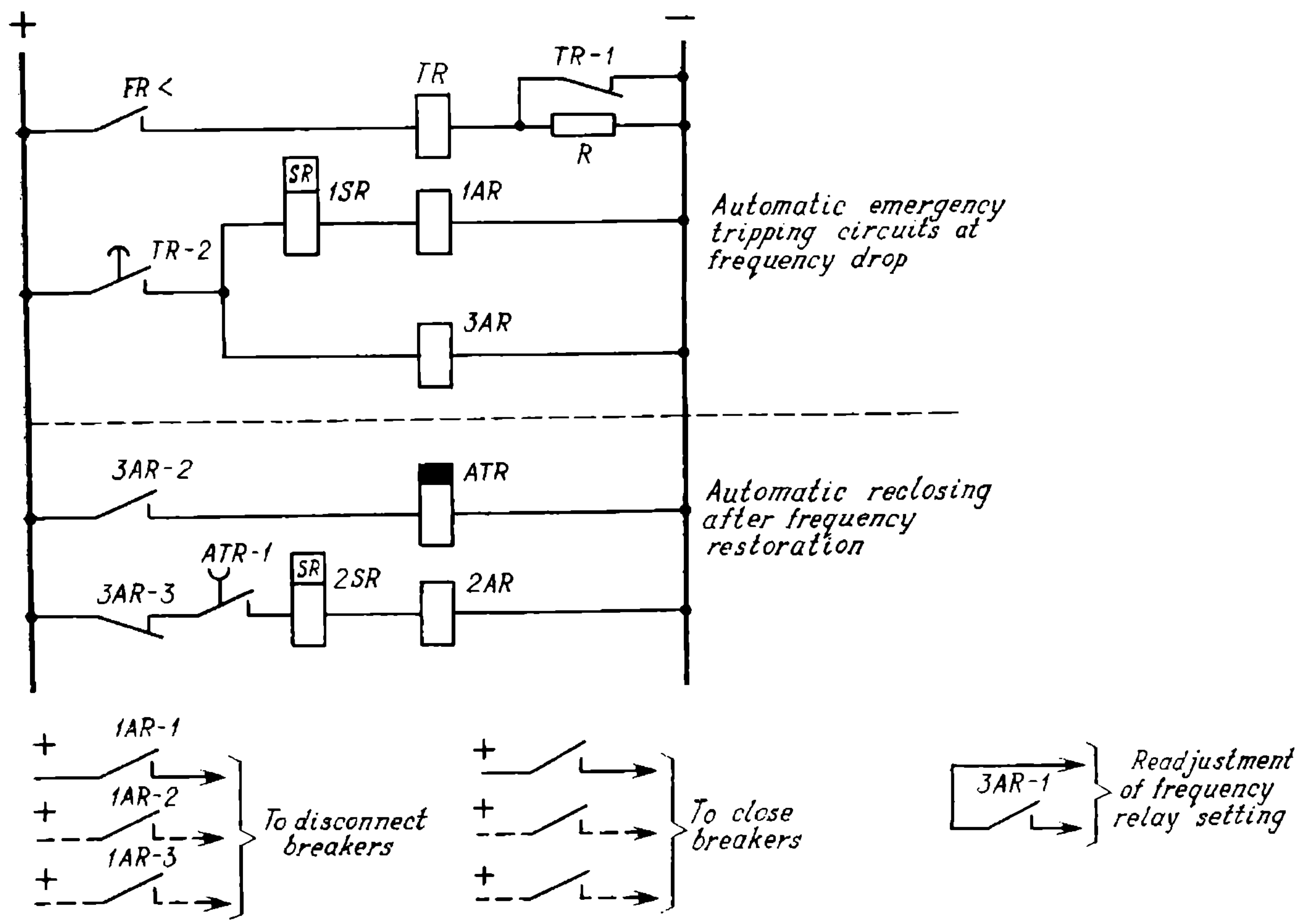


Fig. 5-7. ARC circuit with subsequent ARC after recovery of frequency. FARC device made up of auxiliary relays

FR — contact of frequency relay; *TR* — time relay; *ATR* — relay with delayed armature dropout in reset; *1AR-3AR* — auxiliary relay; *SR* — signal relay. Broken lines indicate the circuits used for disconnection and reconnection of several breakers

The contacts *3AR-1* and *3AR-2* open, while the contact *3AR-3* closes. The relay *2AR* closes and remains in this state until its circuit is opened by the contact *ATR-1*. The relay *2AR* picks up and reverses the breakers. The single-action and short-time nature of the making pulse fed to the circuit is provided by the series connection of the contacts *3AR-3* and *ATR-1*. Operation of the device is indicated by the signal relays *1SR* and *2SR*.

It is advisable to use the device shown in Fig. 5-7 when there is a provision for the automatic reclosure of the given connection only after the tripping

effected by the AFC device and on condition that the normal frequency is established.

In the variant shown in Fig. 5-8 the contact of the underfrequency relay *FR* closes and makes the time relay *TR*. On expiration of the set period, the contact *TR-2* makes and closes the relays *1AR* to *3AR*, and the signal relay *SR* picks up. The relay *1AR* makes the tripping circuits of the breakers. The circuit

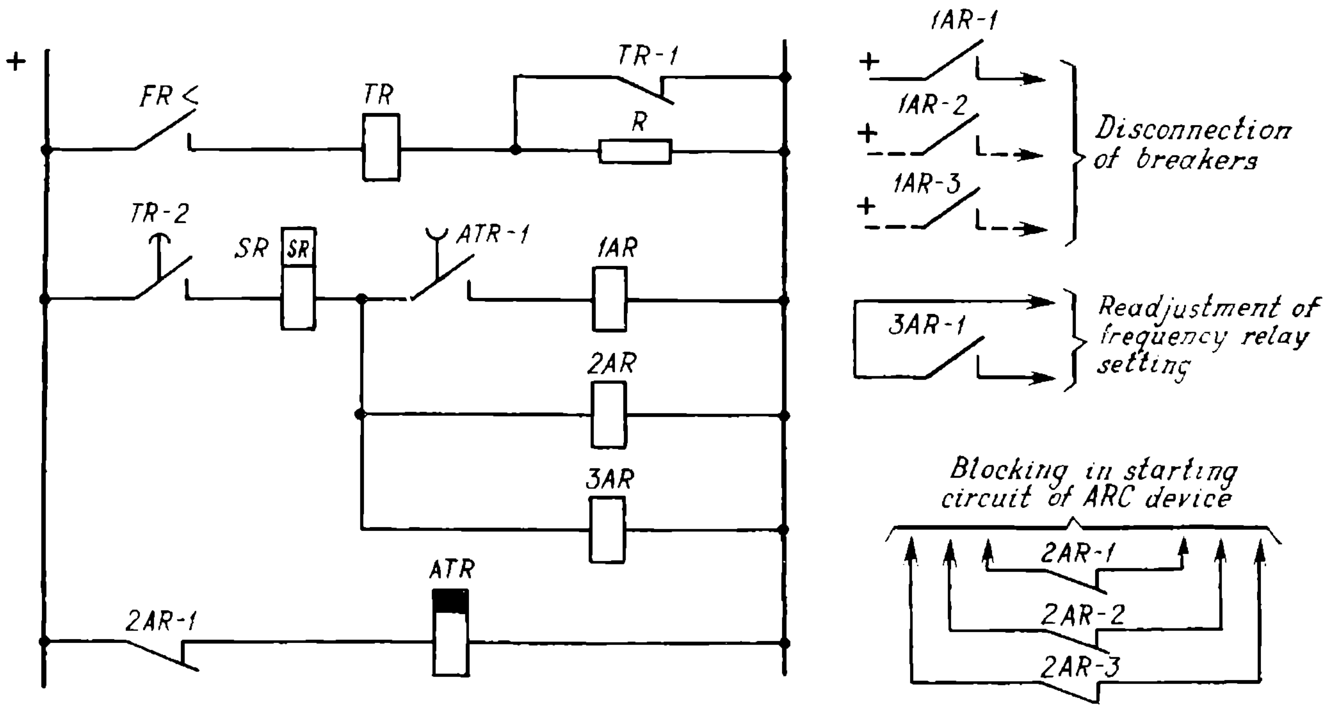


Fig. 5-8. AFC circuit with FARC device employing relay PПB-58
FR — contact of frequency relay; *TR* — time relay; *ATR* — relay with delayed armature dropout in reset; *1AR-3AR* — auxiliary relays; *SR* — signal relay

of the relay *1AR* is controlled by the contact *ATR-1* which is closed when current flows in the coil of relay *ATR*. The contact *2AR-1* breaks the circuit of the relay *ATR*. The contact *ATR-1* in its turn breaks the circuit of relay *1AR* (0.8 to 1.0 second later) and removes the tripping pulse from the breaker.

This circuit of the device permits the opened breakers to be closed manually when the contacts of the underfrequency relay remain closed for a long time (in the case of baked contacts or when an emergency dictates that the consumer be connected manually because of a frequency fall in the power system). This is the advantage of the variant.

Closing the relay *2AR* cancels the operative current flow in the time relay of the ARC unit, thus the frequency recovery is delayed. Reclosure will take place only after the contacts of the underfrequency relay open and the relay *2AR* resets.

Good results are obtained from the circuit shown in Fig. 5-8, when the ARC devices are installed on the connected equipment, regardless of whether the

given equipment is connected or not connected to this or that group of the AFC devices.

When a separated power station is subjected to a heavy power inrush, the reduction in the frequency is accompanied by a drop in the voltage. The operating frequency of a frequency relay decreases with a decrease in the voltage. Under these conditions the AFC devices may fail to operate and, as a consequence, the separated power station may be set to zero voltage. To prevent possible failures of the AFC devices at heavy voltage dips caused by a frequency fall, the AFC devices must be connected to voltage transformers (Fig. 5-9)

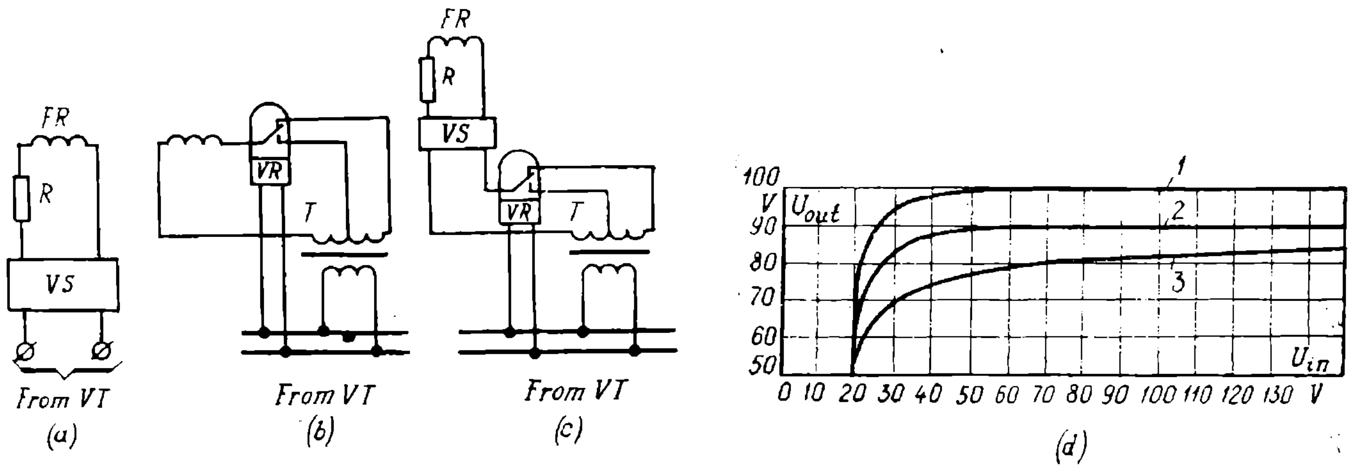


Fig. 5-9. Connection of frequency relay to voltage transformers

(a) through voltage stabilizer *VS*; (b) through intervening transformer or autotransformer *T* and voltage relay; (c) through intervening transformer or autotransformer and stabilizer; *R* — series resistor; (d) stabilizer output voltage U_{out} versus U_{in} at various frequencies: *1* — 50 Hz; *2* — 48 Hz; *3* — 46 Hz

through a voltage stabilizer or through an intervening transformer (autotransformer) with tap changing when a drop occurs in the voltage of the secondary windings so that the transformation ratio can be changed.

It is seen from the output voltage characteristic of the stabilizer that a frequency relay connected to the output terminals of the stabilizer will be at a voltage sufficient for reliable operation of the frequency relay at the preassigned setting, when the input voltage of the stabilizer decreases but not below 30 per cent of the nominal value.

With heavier voltage dips, the operation of the frequency relay may be ensured by means of the circuit shown in Fig. 5-9*c*. The voltage relay setting at which the relay changes over the contacts and raises the input voltage of the stabilizer may be taken 30 to 40 V.

The operating time of the AFC devices utilizing the circuits shown in Fig. 5-9*b* and *c* should be not less than 0.5 s to provide reliable discrimination against short-time bridgings of the frequency relay contacts occurring when switching the voltage circuits by the contacts of relay *VR*. Connecting the frequency relay through a voltage stabilizer does not require such switching of the voltage circuits and in this respect it has an advantage over the circuits in Fig. 5-9*b* and *c*.

5-6. Induction Frequency Relays, Type ИВЧ-011 (ИВЧ-3)

For the internal connections of the relay and the construction of its sensing element see Fig. 5-10. Magnetic structure *1* carries four series-connected coils *2* which together with capacitor *C* form an inductive-capacitive circuit (circuit *I*). A current flow in this circuit builds up the flux Φ_1 in poles *3* and *4*.

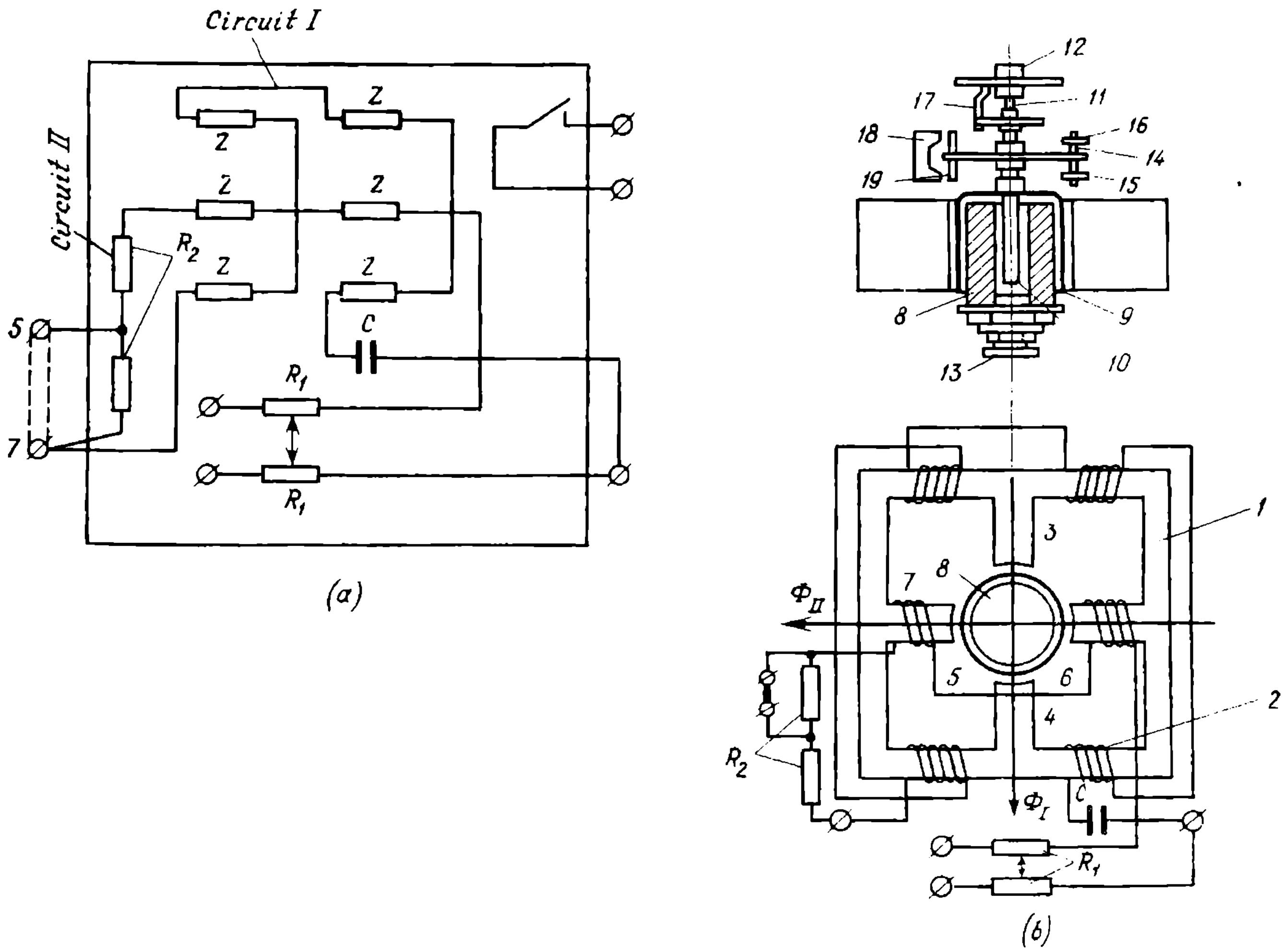


Fig. 5-10. Frequency relay, type ИВЧ-011
(*a*) relay internal connections; (*б*) relay construction

Poles *5* and *6* carry two *Z* coils which together with resistors R_1 and R_2 form an inductance-resistance circuit (circuit *II*). The current flow in this circuit builds up the flux Φ_{II}.

Voltage is supplied to both of those circuits from the secondary windings of an instrument potential transformer (directly or through a voltage stabilizer). The required torque is determined by the following expression

$$M = k\Phi_{II}\Phi_I \sin\psi \tag{5-37}$$

where k = proportionality factor

ψ = angle between the flux vectors $\dot{\Phi}_I$ and $\dot{\Phi}_{II}$

Capacitance C and resistance R are so selected that the angle between the $\dot{\Phi}_I$ and $\dot{\Phi}_{II}$ vectors is zero, i.e., the torque is equal to zero (more exactly, it is insufficient to overcome the torque of spring *17*). The relay contacts in this case are open. When the frequency varies, the angle $\psi \neq 0$ and the relay rotor, aluminum sleeve *9* fixed on pin *10*, tends to turn. In the case of an increase in frequency, the flux $\dot{\Phi}_I$ lags the flux $\dot{\Phi}_{II}$ and the torque assists in opening the contacts. When the frequency decreases, the flux $\dot{\Phi}_I$ leads the flux $\dot{\Phi}_{II}$ and the relay closes its contacts.

The operating setting of the relay is controlled by means of a double rheostat R_1 integral with the relay case. The relay scale may be changed by varying the resistance R_2.

The relay has a permanent magnet *18* acting upon steel rod *19* whose function is to add a counter torque to the torque of spring *17*. Such a construction improves the performance of the relay as the frequency slightly departs from the operating frequency when the spring torque is insufficient. In addition, it improves the reset factor of the relay. Aluminum sleeve *9* is positioned in the air gap between the relay poles and steel cylindrical core *8*. Pin *10* is fixed by polished steel journals *11* which are carried by upper bearing *12* and lower bearing *13*. Relay contacts *15* and *16* are shorted clockwise by silver rocking bridge *14* of sleeve *9* (top view).

Given in Fig. 5-11 is the relay circuit with a minor alteration in the internal connections in order to switch over the reset setting of the relay after function of the AFC device. The switching is accomplished by closing the relay contact *3AR-1*. The reset setting of the relay can be changed after it has picked up, which is clear from its vector diagram (Fig. 5-12).

Let voltage U_r at frequency $f = \omega/2\pi$ Hz be applied to relay circuits *I* and *II*.

The shift angle φ_I between the current vector $\dot{I}_I$ and the voltage vector $\dot{U}_r$ is determined by the relationship between resistance R_I and inductive reactance x_I of circuit I

$$\left.\begin{aligned} Z_I &= R_I + jx_I \\ \tan\varphi_I &= \frac{x_I}{R_I} \end{aligned}\right\} \qquad (5\text{-}38)$$

The shift angle φ_{II} between the current vector I_{II} and the voltage vector $\dot{U}_r$ is determined by the relationship between resistance R_{II} and inductive reactance x_{II} of circuit II

$$\left.\begin{aligned} Z_{II} &= R_{II} + jx_{II} \\ \tan\varphi_{II} &= \frac{x_{II}}{R_{II}} \end{aligned}\right\} \qquad (5\text{-}39)$$

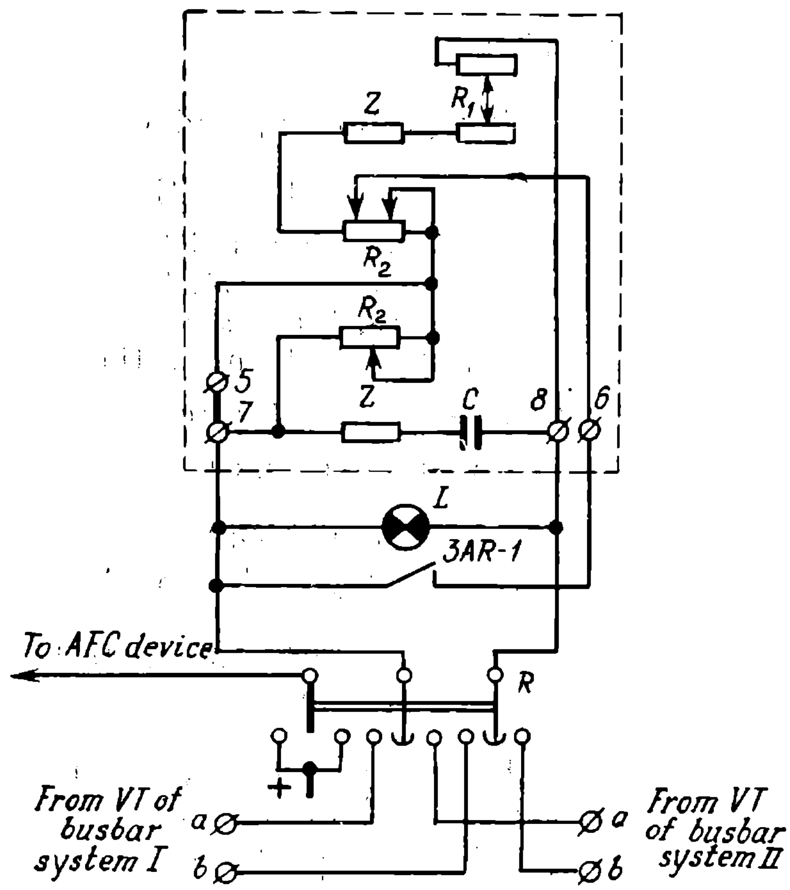


Fig. 5-11. Connection of underfrequency relay ИВЧ-011 when **reset setting** is controlled

3AR-1 — relay contact to control reset setting; *S* — knife switch (when turned on, its blades sypplying a.c. voltage are closed first and then its blade supplying d.c. power is closed; the order is reverse when the switch is opened); *L* — pilot lamp indicating presence of voltage

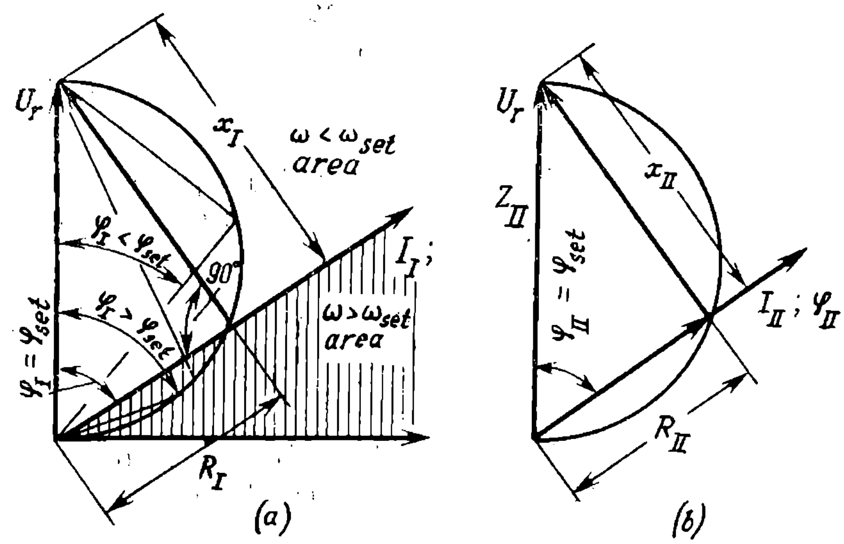


Fig. 5-12. Operating diagram of relay ИВЧ-011 (ИВЧ-3)

(*a*) vector diagram of currents and voltages of relay circuit I; (*b*) same of relay circuit II

The inductive reactance of circuit I is

$$x_{\mathrm{I}}=\omega L_{\mathrm{I}}-\frac{1}{\omega C_{\mathrm{I}}} \tag{5-40}$$

At a frequency equal to the preassigned setting value ($\omega = \omega_{set}$) the inductive reactance x_{I} has a definite value

$$x_{\mathrm{I}}=x_{set}=\omega_{set}L_{\mathrm{I}}-\frac{1}{\omega_{set}C_{\mathrm{I}}} \tag{5-41}$$

Since R_{I} is constant, the angle between the current $\dot{I}_{\mathrm{I}}$ and the voltage $\dot{U}_r$ will change with a change in the frequency.

When the frequency decreases as compared with the operating setting frequency, the reactance x_{I} and the angle φ_{I} decrease and vice versa.

The inductive reactance of circuit II is

$$x_{\mathrm{II}}=\omega L_{\mathrm{II}} \tag{5-42}$$

At a frequency equal to the preassigned setting value of operating frequency the reactance is

$$x_{\mathrm{II}}=x_{set}=\omega_{set}L_{\mathrm{II}} \tag{5-43}$$

Using the variable resistor R_2, set the resistance of circuit II so that

$$\varphi_{\mathrm{II}}=\varphi_{\mathrm{I}} \tag{5-44}$$

In this case the impedance Z_{II} will have a definite value with $\omega = \omega_{set}Z_{\mathrm{II}} = \xi Z_{\mathrm{I}}$, where ξ is the proportionality factor. The directions of the currents $\dot{I}_{\mathrm{I}}$ and $\dot{I}_{\mathrm{II}}$ and fluxes $\dot{\Phi}_{\mathrm{I}}$ and $\dot{\Phi}_{\mathrm{II}}$ are the same and the angle φ between the fluxes is zero. The torque of the relay is also zero and, if there is no spring torque, the relay is in a position of indifference.

If the system frequency exceeds the operating frequency the reactance x_{I} *increases* to an amoun greater than the reactance x_{II}. The flux $\dot{\Phi}_{\mathrm{I}}$ begins to lag the flux $\dot{\Phi}_{\mathrm{II}}$ and the relay torque acts to open the contacts.

If the system frequency decreases in comparison with the operating setting frequency, the reactance x_{I} *decreases* more than the reactance x_{II}; the flux $\dot{\Phi}_{\mathrm{I}}$ starts to lead the flux $\dot{\Phi}_{\mathrm{II}}$ and the relay closes the contacts (function of the underfrequency relay is meant).

After the relay contacts have closed they will again open, if the direction of the vector $\dot{\Phi}_{\mathrm{I}}$ coincides with that of the vector $\dot{\Phi}_{\mathrm{II}}$. To overcome the friction torque, the vector $\dot{\Phi}_{\mathrm{I}}$ must somewhat lag the vector $\dot{\Phi}_{\mathrm{II}}$ in order to promote a negative torque so that the relay is reset at a frequency a bit higher than the operating frequency. This determines the reset factor of the relay. This design allows the reset frequency to be changed. To *increase* the reset frequency, it is sufficient, when the contacts are closed, to *increase* the angle φ_{II} between the current $\dot{I}_{\mathrm{II}}$ and the voltage $\dot{U}_r$, i.e., to displace the flux $\dot{\Phi}_{\mathrm{II}}$

direction towards the horizontal axis. Such an increase in the angle φ_{II} is obtained by reducing the resistance R_{II}.

As said above, a similar method is used to control the reset frequency setting of the frequency relay employed by the FARC devices. It is clear from the diagram in Fig. 5-12 that the relay, type ИВЧ-011 (ИВЧ-3) may perform the function of an overfrequency relay. To this end, it is sufficient to change the connection polarity of the first circuit or change the position of the contacts by arranging them so that they close when the flux $\dot{\Phi}_I$ lags the flux $\dot{\Phi}_{II}$.

5-7. Frequency Relays, Type РЧ-I, Employing Semiconductor Elements

Since 1971 the underfrequency relays, type РЧ-I (Fig. 5-13), based on semiconductor and logic elements are manufactured in the USSR. The relays are free of the imperfections inherent in the type ИВЧ relays, i.e., the setting

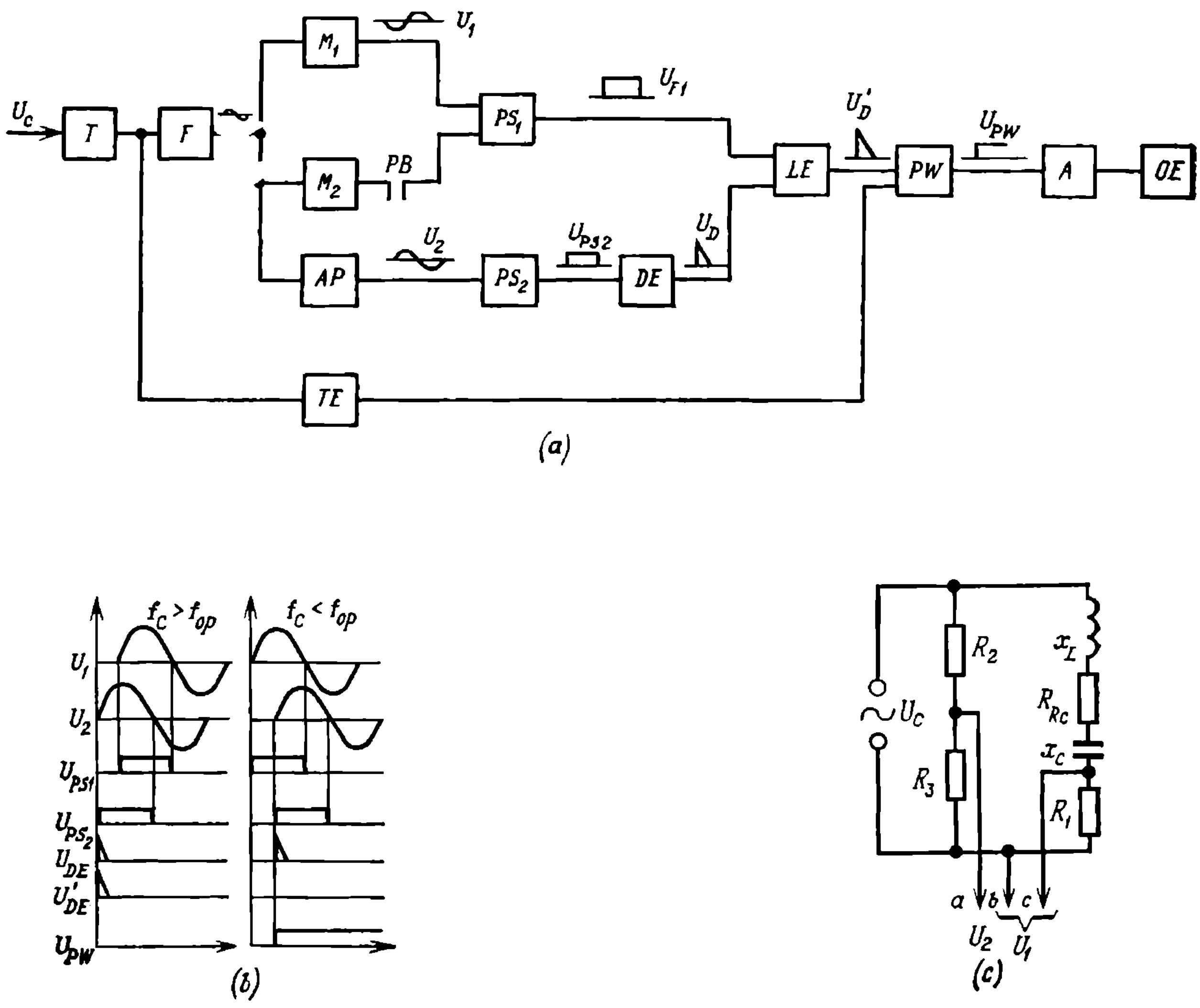
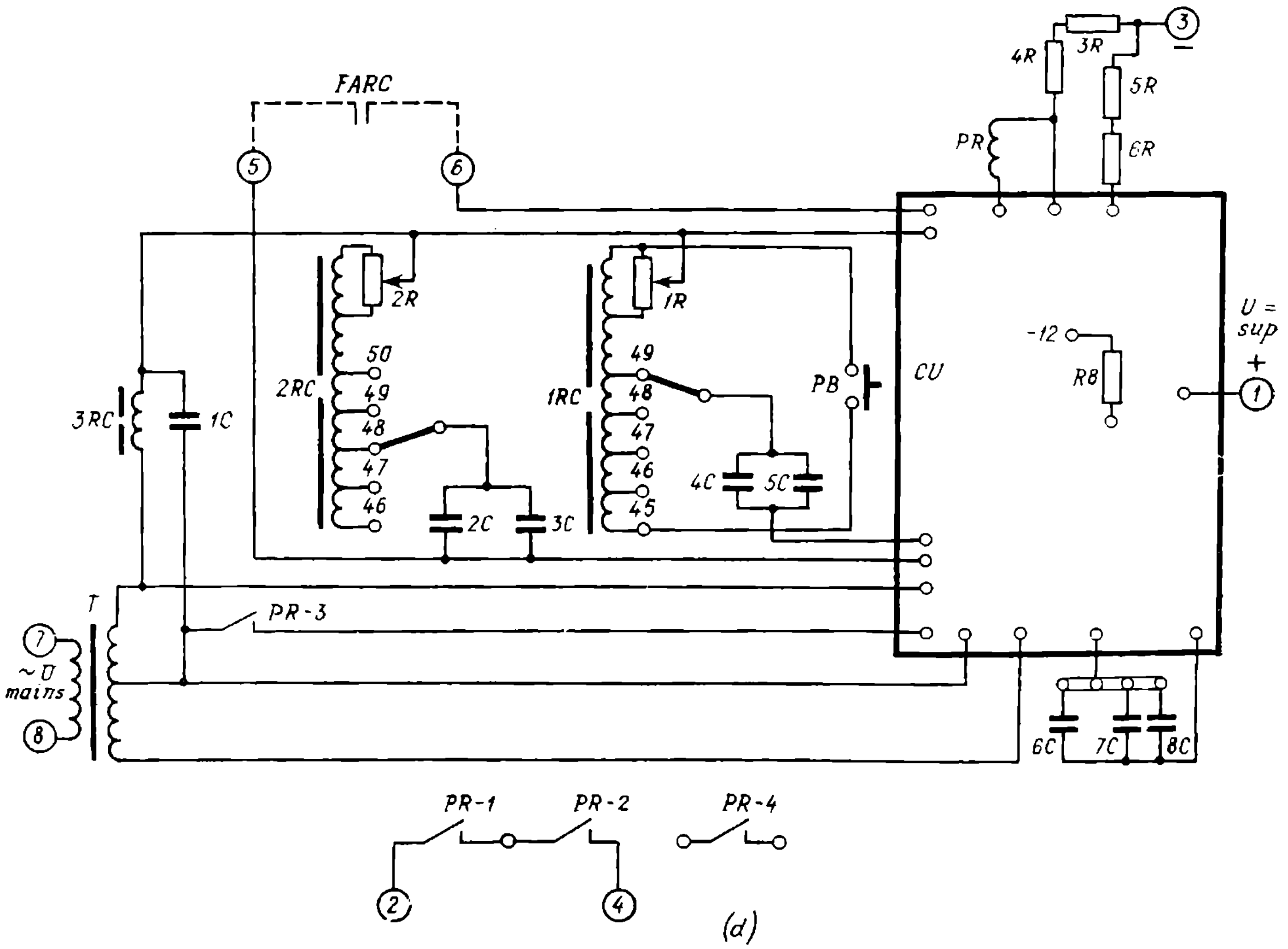


Fig. 5-13. Semiconductor
(a) block diagram; (b) time-pulse diagrams; (c) phase-shift networks; (d) simplified schematic dia

of the РЧ-I relay is practically independent of the voltage magnitude and does not misfunction when the voltage suddenly changes. For a complete internal wiring diagram of the relay see reference [5-10].

Through a decoupling transformer T and a band filter F which eliminates the effect of the upper harmonics on the operation of the relay, the voltage U_c of the circuit under control is applied to the phase-shifting circuit. This circuit includes a frequency indicating (measuring) element M_1 and active divider AD. The angle between the voltages U_1 and U_2 at the output of the phase-shifting device is determined by the circuit frequency at the input of the relay. These voltages are passed to the phase-sensing element which consists of two pulse shapers, PS_1 and PS_2; a differentiating element DE and a logic element LE. Developed at the output of the pulse shapers are rectangular pulses U_{PS_1} and U_{PS_2} whose duration is close to the half-cycle of the input voltage.

A short (braking) pulse U_D is formed from the leading edge of pulse U_{PS_2} by means of the differentiating element DE. The relative position of pulses U_{PS_1}



underfrequency relay РЧ-I

gram (shown in broken line are circuits used to control reset setting of frequency relay)

and U_D depends on the circuit frequency. These pulses are fed to the logic element *LE* ("prohibition") which permits further passage of the braking pulse only when no pulse U_{PS1} is present at the input.

If the circuit frequency is higher than the operating frequency of the relay ($f_c > f_o$), a pulse U'_D is produced every half-cycle at the output of the element *LF* and does not occur when f_c is less than f_o. The pulse is widened in time by the pulse widener *PW* designed so that the output control signal is absent when the signal is fed to its input and vice versa.

The trigger element *TE* which starts *PW* only when the relay input is at the a.c. voltage of the circuit prevents misoperation of the relay when the circuit voltage disappears.

The control signal from *PW* is fed through amplifier *A* to the output element *OE*.

The phase-shifting network converts the circuit frequency changes into changes in the angle φ between the $\dot{U}_1$ and $\dot{U}_2$ vectors. When voltage measurements are made between points *a* and *b* (Fig. 5-13*c*) the angle between the $\dot{U}_1$ and $\dot{U}_2$ vectors is determined from the expression

$$\tan \varphi = \frac{\omega L - \dfrac{1}{\omega C}}{R_1 + R_{rc}} \tag{5-45}$$

An 0.4° change in the angle φ corresponds to a change of 0.1 Hz in frequency.

As pointed out above, the relay is connected through transformer *T* (Fig. 5-13*d*). Reactance coil *3RC* and capacitor *1C* form a band low-pass filter. Reactance coil *1RC* and capacitors *4C* and *5C* with a resistor found in the converter unit *CU* form a phase-sensitive network controlled by push-button *PB* used to check the relay condition. Another phase-sensitive network performing the function of the working element of the relay is formed by reactance coil *2RC*, capacitors *2C* and *3C* and a resistor located in the converter unit. One of the two phase-sensitive networks may be used for changing the reset setting of the relay (for the FARC) or for promoting the operation of the second group of the AFC devices.

The operating frequency may be adjusted either in 1-Hz steps by a switch or continuously within 1 Hz by means of resistors *1R* and *2R*. The time setting of the relay is controlled by changing the circuit capacitance with the aid of capacitors *6C* through *8C*.

Relay specifications. The rated voltages are 100 volts for an a.c. circuit under control and 110 and 220 volts for the operating direct current circuit.

The operating setting range is from 45 to 50 Hz and the reset values range from 46 to 51 Hz. The minimum difference between the operating and reset frequencies is less than 0.1 Hz. The operating frequency is true to 0.2 Hz when the voltage across the circuit under control varies from 0.2 to 1.3 of U_{rated}. Variations of the ambient temperature from —20 to +40°C change the operating

frequency only by 0.2 Hz max. and from —40 to +40°C by 0.3 Hz max. The operating time settings are 0.15, 0.3 and 0.5 s.

The power consumption is 10 VA max. for the a.c. circuits, 10 W max. for d.c. circuits at 110 volts and 20 W max. for the d.c. circuits at 220 volts.

The a.c. and d.c. circuits allow prolonged operation of the relay at 110 per cent of U_{rated}.

The base and dimensions of the relay are the same as those of the ИВЧ-3 unit. The d.c. output is from terminals *1* and *3*. The power is applied to terminals *7* and *8*. The relay reset setting for operation of the FARC unit is changed by reconnecting contacts *5* and *6*. The output circuits are connected to terminals *2* and *4*.

5-8. Conclusions

1. The AFC devices are essential elements used in automatic power control systems to prevent faults involving avalanche falls of frequency and voltage, which results in outages and prolonged interruptions in the power supply.
2. The use of grid power systems adds to the likelihood of severe local power lacks in separate areas if they are isolated from the rest of the system due to a fault.
3. In large power systems numerous emergencies resulting in critical falls of the frequency are possible, therefore the AFC system must be capable of "self-adjustment", i.e., whatever the fault, the amount of tripped load must correspond to the power deficit. This requirement is not met by the AFC devices with a small number of frequency control groups when these devices are serving large power consumers.
4. The AFC system with two frequency-control categories, AFC-I and AFC-II, and with a large number of groups in each category considerably satisfies the "self-adjustment" requirement. Coordinated operation of the AFC-I and AFC-II categories is a further development of this system.
5. The further improvement of the AFC system will be apparently combined with the operation of an automated load-control system to which will be added the function of control of the AFC devices (parameter adjustments, determination of required unloading, etc.).
6. Combined operation of the AFC and FARC devices facilitates recovery of the normal power supply after clearing the cause that made the AFC devices function and corrects malfunctioning of the AFC devices when short-duration falls in the power system frequency occur.
7. To prevent the AFC devices, at substations having synchronous and asynchronous motors, from misoperation when the feeder is tripped blocking should be applied. For this, active power or current relays which open the operative circuit of the AFC device when the feeder is tripped can be used.
8. When a power station with a heavy power deficit is isolated from the rest of the power system under an emergency, the separated area must be provided with local frequency control in addition to the AFC system. The local frequency control units must automatically come into operation when the

area is disconnected. This function can be accomplished by active-power directional relays, devices responsive to the rate of frequency changes, etc.

9. When tripping the areas having a large active power deficit the frequency fall is accompanied by heavy voltage drops. If the functioning of the frequency relay employed by the AFC device or by the automatic frequency sectionalizing controls is dependent on the voltage applied, the frequency relays must be connected through a voltage stabilizer or a special autotransformer with tap-changing in case of voltage drops.

5-9. Review Questions

1. What is the purpose of automatic frequency control? Why are AFC devices considered as important elements in power automatic control systems to prevent faults affecting the entire system?
2. What are the advantages and disadvantages of the AFC system with a great number of frequency control groups?
3. What are the purpose and values of the time settings used by the AFC-I and AFC-II devices?
4. Draw a diagram of an AFC device with blocking from an active-power relay responding to the real power flow in the feeder. What should be the operating setting of this relay?
5. What are the purpose and settings of the FARC devices?
6. Describe the operating principle of the ИВЧ-3 (ИВЧ-011) induction frequency relay.
7. Describe the operating principles and characteristics of the РЧ-I semiconductor frequency relay.
8. How are the operating and reset frequency settings of the ИВЧ-4 and РЧ-I relays adjusted?
9. What is the purpose of the additional (in a local area) frequency control and the automatic sectionalizing controls responding to frequency?
10. What are the causes of possible operation of the frequency relays of AFC devices in the case of loss of synchronism in a power system?
11. Name the causes of short-time decreases in the power system frequency where a spinning power reserve is available.
12. What are the methods of using underfrequency relays as overfrequency ones?
13. Name the variants of the FARC device circuit. Evaluate these variants.
14. Describe the methods improving the operating stability of frequency relays when the voltage decreases. What are the conditions which make it necessary to eliminate the dependence of the operating setting of the ИВЧ-011 relay on the value of the voltage applied?
15. To guarantee the maximum load in a 5000 MW power system without decreasing the frequency below 50 Hz, when the generation capacity is fully used, a 50 MW consumption limit is introduced for peak hours. What will be the fall in the power system frequency during peak hours if this limit is not introduced and also if a decision is made to limit the power consumption only by 25 MW ($K = 2$)?

Chapter Six

AUTOMATIC CONTROL OF FREQUENCY, REAL POWER AND POWER FLOWS IN POWER SYSTEMS

6-1. General

When load dispatching, the current frequency in power systems must be continuously sustained at a value of 50 ± 0.1 Hz. Short-time operation at a frequency sustained within ± 0.2 Hz is allowed. In this case, the difference between astronomical time and synchronous electric clock time should not be greater than ± 2 minutes in 24 hours.

When the frequency falls below the specified value, the dispatcher of the grid (integrated) or of a separately operating power system must bring the available power reserves into action. If the load frequency continues to fall and all the reserves available are exhausted, the dispatcher must ensure reestablishment of normal operating conditions by limiting or tripping some loads in compliance with the load-frequency regulating instructions [6-1, 6-2].

Failure to observe the standard requirements for the power supply quality results in power overconsumption and causes a labour productivity reduction in industry. Prolonged operation at a lowered frequency (below 49.5 Hz during 1 hour and below 49 Hz for more than 30 min) is economically so unattractive that is regarded as a system-scale fault [6-3].

In the first stage of the development of Soviet power engineering, when many systems were used separately, the load frequency might undergo fairly wide variations, but in large power systems, like the integrated power grid system in the European USSR (such systems produce about 80 per cent of the total electrical energy in the country) the load frequency is now sufficiently stable Fig. 6-1.

Comparison of frequency records shows that the use of automatic load-frequency control (secondary) reduces the amplitude of the frequency variations about the mean value. These variations, however, do not exceed the limits specified in the GOST standards even in the absence of control.

Therefore, in integrated power systems having generated power reserves the main task is to obtain (with the load frequency kept at the specified value) the most economical load allocation among the units operating in parallel.

In the conditions of integrated power systems, the complete and economical utilization of the generated power at the stations sometimes is not feasible due to insufficient transmission capacity between and in the links used in the systems. Under such conditions the main purpose of the automatic control

devices is to ensure the maximum practicable power transmission over those links as can be permitted by the steady-state stability requirements.

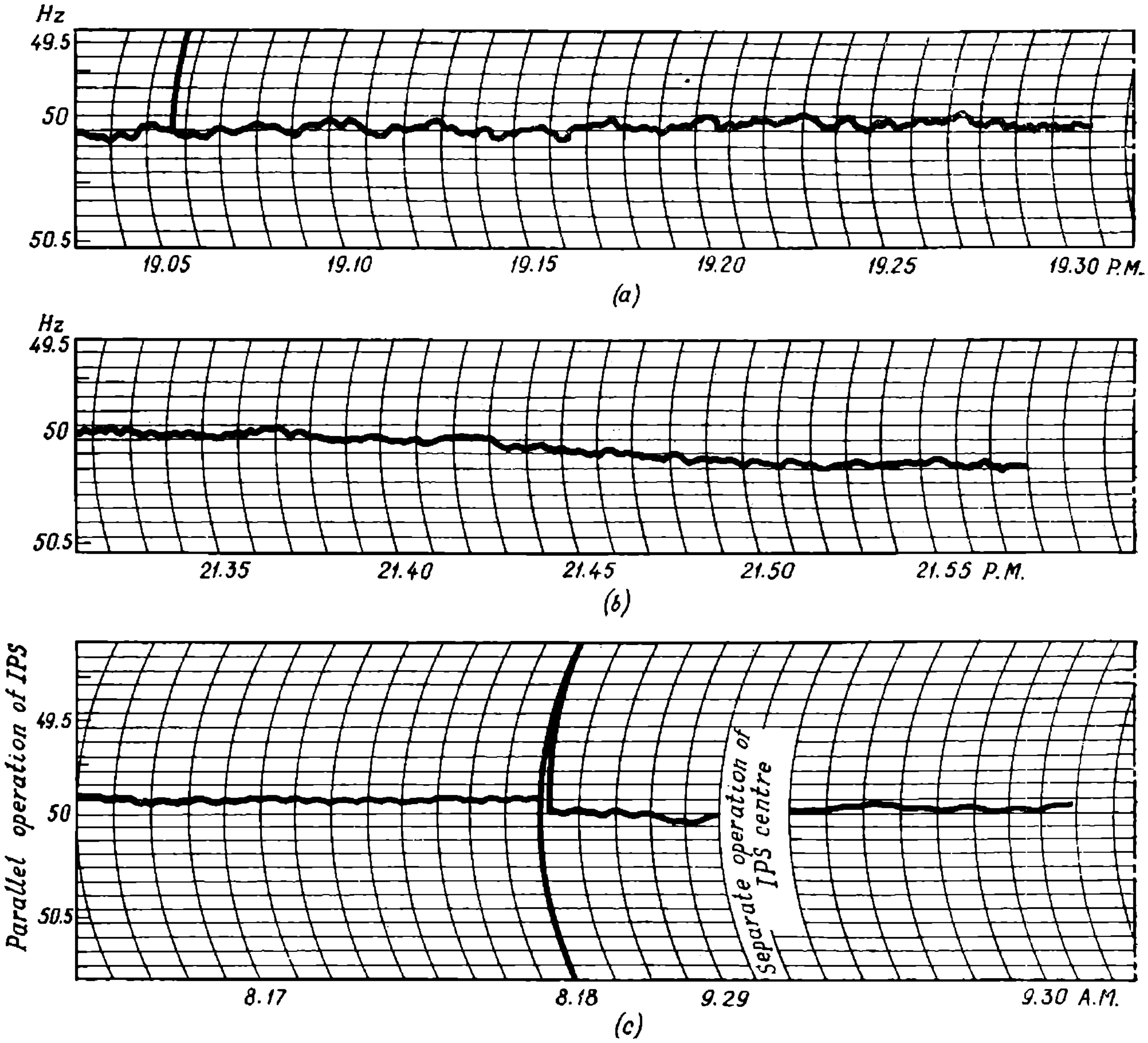


Fig. 6-1. Frequency variations in power system

(a) separate operation of parts of integrated power system; no frequency regulators are used at regulating stations; (b) parallel operation of integrated system; no frequency regulators are used at regulating stations; (c) frequency regulators are turned on. Parallel operation of power system parts is shown in the left-hand part of accelerated record of recording frequency meter. Separate operation of IPS parts is shown in the right-hand portion

If the amount of the power exchange between the power systems is specified in an agreement, a factor often practised in many countries, or when this amount is specified according to a load-control schedule, then maintenance of the specified power may also be placed with the automatic control devices.

Thus, nowadays automatic control devices are responsible for sustaining the load frequency of the integrated system, economical load allocation among

the paralleled generating units, and control (limitation) of power flows over insufficient tie links between power systems and inside them.

The modern systems for automatic control of load-frequency, real power and power flows (AFP & FC) incorporate:

Primary speed governors designed to maintain the speed of the turbine-generator unit, when the generator load varies, by changing the steam (or water) supply to the turbine in compliance with the load. The design of the governor can limit the steam (water) supply to the turbine to a maximum value when loads are excessive, and to a minimum value when the loads on the generator are below the preassigned values.

The closer these minimum and maximum values to one another, the easier the operating conditions for the speed governor, but the generating unit is less able to participate in the common control process.

It is important that the maximum value does not interfere with the full use of generation and can even permit a certain overload, when the system suffers from an emergency lack of power, and the minimum value does not hinder the less economical generating units from being unloaded, when the more economical units produce reserve (excess) output.

It should be noted that the minimum load and also the control range of the thermal generating units is significantly dependent upon the types of boilers, turbines, fuel used, etc.

When a generator suddenly throws off the load, the action of the speed governors must prevent the functioning of the safety automatic controls which are installed on the turbines as a guard against overspeeding and assist the speed governors' protective action. The overspeed value at which the safety controls come into action is equal to 112 per cent of the nominal value for high-speed steam turbine generators and 130 per cent for low-speed hydroelectric generators.

Secondary control devices. Where a control range is provided, the secondary control devices help to keep the turbine speed constant (constant frequency) at any value of load. These act upon the primary governor via a speed changer in case of changes in the load frequency, power flows, etc. The devices operate in conjunction with the devices for the group control of active power generation at a multi-unit power station. The group control devices allow the power station whose units are under such control to be regarded as a single plant that can be acted upon by a controller determining the participation of the power station as a whole in the common system of frequency and power output control.

The group control devices used immediately in the power station must ensure the most economical load allocation among the individual units, in particular on the basis of observing the equality of relative increments in the cost of the fuel consumed by the individual units of the group.

To make the joint operation of power stations with the group control of the units feasible, the power controllers of these devices should be controlled either from a common system regulator providing for the specified mode of regulation and the share of each power station in the common power regulation process or should operate in compliance with the specified load schedule; it is important

that the schedule be corrected as to the frequency and real power flow over the tie lines.

In the so-called decentralized control systems the group control devices of individual stations used an astronomical time clock as the central regulator. Such a reference clock had to be installed at each power station to provide exact time indication within a 24-hour period to ± 0.05 s.

System control devices act upon the station generators through the group control systems and control the load frequency, real power and power flows in the power system and its parts.

With a centralized AFP & FC system, the control pulses acting upon the station controllers are produced by the central regulator. The required input information and mode of regulation are preset, the controllers of the group control devices of the individual power stations being acted upon by remote control. In practice, this type of centralized regulation was used in small power pools working in isolation from the integrated power system or was used as a means of centralized control of a group of power plants from the load dispatching department of the power system.

With the decentralized AFP & FC system, the control signals acting upon the generating units were to be executed by devices installed only at the regulating power stations without using remote control. However, the necessity to correct the output of certain power stations with the aid of the power flows on the transmission lines made it impossible to give up remote control and in fact caused an increase in the number of the remote control channels.

Due to integration of the power systems the decentralized regulation method turned out to be unfeasible as it was necessary to limit the action of the group control devices with regard to power flows in the tie lines and to take into account the losses in the transmission lines, all of which needs a fairly large amount of remote control equipment. The group control devices installed in some of the power stations for decentralized regulation have proved useful in accomplishing power flow limitations on tie lines [6-4].

With the mixed AFP & FC system used in the integrated power systems of the USSR economical load allocation among the generating units is obtained by using a preplanned schedule prepared in each power system by group control station controllers. Practice shows that unplanned departures from the properly designed load schedules do not exceed 2-3 per cent. The variations cause changes in the volume of planned power flows over the tie lines and in the power system frequency. Correction of the above-mentioned parameters is placed with the central regulator acting upon a certain number of the power stations which deal with unplanned loads. In a number of cases the task of handling unplanned loads is assigned to one hydroelectric power station possessing the needed generation reserve. Simultaneously this station perform the load-frequency regulation function. The central regulator must consider the power exchange capacity of the tie links between power systems and never permit dangerous overloads.

The principle according to which a regulating power station performs the load frequency and power flow control functions is given by the following

expression [6-5]

$$P = P_{pl} + K_1 \int_0^t \Delta f \, dt + K_2 \Delta f + C_1 \int_0^t \Delta P_{fl} \, dt + C_2 \Delta P_{fl} \qquad (6\text{-}1)$$

where P = power output of the regulating (pilot) power station
P_{pl} = planned power of a power station (optimum when there is no departure from the planned value)
Δf = frequency departure from the preassigned (rated) value
ΔP_{fl} = power flow departure from the planned value
K and C = regulation factors determining the share of the regulating station in the control of unplanned load changes. The factors are selected so that optimum regulation is achieved

When several power stations handle the unplanned load variations their group control systems are activated from a central regulator installed at the load control centre. The participation of each power station is determined by operators and executed through the central regulator. The flow limiters which limit the power generated by the regulating station or stations act upon the group control system of the given power station either directly or through the share controller of the central regulator (or by both methods). 9

The dispatcher should be able to change the settings of the reference frequency unit which determines the load frequency of the system, and the device which allocates the share of one or another power station handling the unplanned loads and the control units limiting the tie link power flows. When the dispatcher cannot directly control the settings of the corresponding apparatus, functions similar to the above must be performed by the station operators according to the directions of the power system dispatcher or independently making the necessary corrections against instrument readings.

In addition to the principal functions of regulating the frequency, power and power flows in the power system as a whole, the AFP & FC systems must provide the rated frequency in isolated parts of the system operating asynchronously in order to facilitate the subsequent synchronization and recovery of normal operating conditions. For this each power system in the integrated system is furnished with AFP & FC devices that are operated by control personnel when one or another part of the integrated system is separated for individual operation. The central regulators used in the isolated parts of the integrated power system control a limited number of power stations.

When accomplishing such a system of mixed regulation the central regulator of the integrated power system may act upon the regulating power stations through the regulators of individual parts of the power system rather than directly.

6-2. Frequency and Power Regulators

The primary regulator of the load-frequency and real power or, in other words, the speed governor is a process apparatus without which the turbine-generator unit cannot work under conditions of varying load. If the generating unit

operates at a preassigned speed (at a preassigned frequency) and under a certain electrical load, the amount of steam (or water) supplied to the turbine corresponds to this load. With a change in the electrical load and no change in the amount of steam (water) fed to the turbine per unit time its speed will alter and the generating unit will decelerate if the electrical load increases or accelerate if the electrical load decreases.

To automatically reestablish the initial speed, the steam (water) flow to the turbine and the electrical load must be brought into agreement. This is

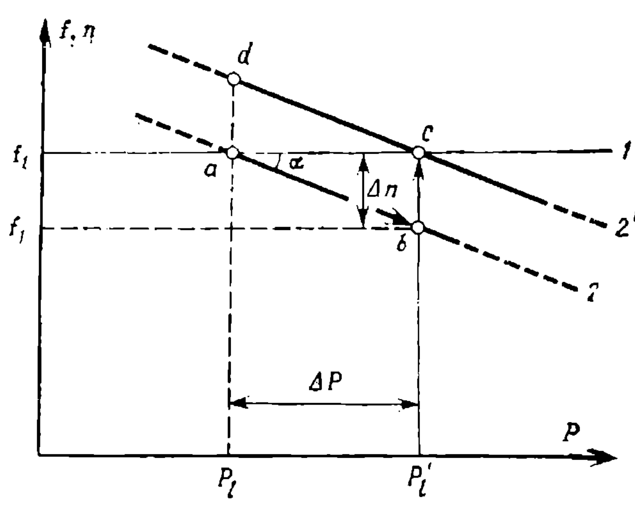


Fig. 6-2. Characteristics of speed regulation by the primary governor

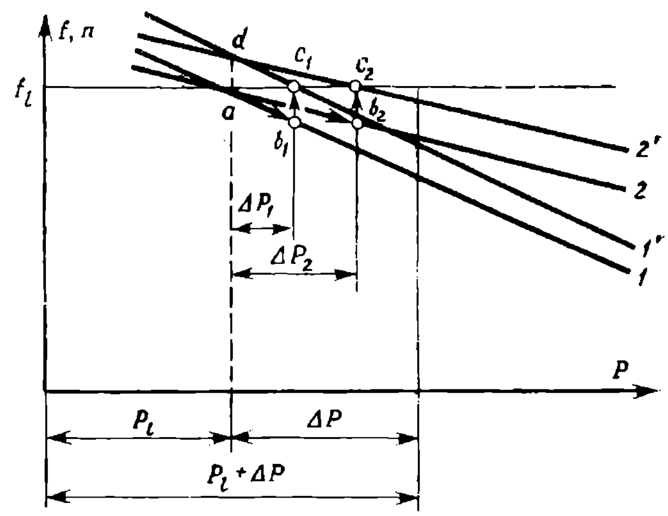


Fig. 6-3. Load sharing among generation units with different steady-state characteristics $n = \varphi(P)$

provided by the primary speed governors. Usually these are mechanical centrifugal regulators which, as others, can regulate according to the transient (*1*) or steady-state (*2*) characteristics (Fig. 6-2).

In some constructions the mechanical speed change detector is replaced by or supplemented with an electrical sensing unit (a load-frequency control attachment).

In the transient mode of regulation the process takes place without appreciable overcorrection and residual decrease in the speed as the generator load increases. The characteristic $n = \varphi(P)$ at each time instant is determined by a straight line parallel to the axis P. In the steady-state mode of regulation the steam (water) flow to the turbine changes only after a certain speed change.

When the load frequency (speed) of the generating unit falls from f_l (point *a*) to f_1 (point *b*), the primary speed governor will increase the turbine steam (water) supply and the load will rise from P_l to P_l'.

New steady-state operation results. The section *bc* determines the residual noncompensation of the speed during the regulation process, i.e., the steady-state error.

The steady-state coefficient s is equal to the ratio of the speed change to the incremental output power

$$s = \tan \alpha = \frac{\Delta n}{\Delta P} \qquad (6\text{-}2)$$

The steady-state nature of the regulation characteristics makes parallel operation of turbine-generator units into a common load possible. If there are a number of paralleled machines, then a change (say, an increase) in the total load by ΔP is accepted by the machines in accordance with the steady-state coefficient of the primary regulation. The units having regulation characteristics less steady (compare characteristics *1* and *2* in Fig. 6-3) will be loaded to a greater degree (in percentage of the rated power). In generating units with transient characteristics the entire load will be shared by these machines by loading them to a value determined by the limiter settings.

The secondary regulators of load-frequency and real power make it possible to restore the frequency to the initial (nominal) value after operation of the primary regulators having a steady-state characteristic. The secondary automatic regulation device responds to a decrease in power system frequency from f_l to f_1 (Fig.6-2) and actuates the primary regulator until the speed of the generating unit and thus the frequency of the power system are at the rated values. This instant corresponds to the point c. The frequency regulator characteristic has been displaced parallel to itself to the position determined by the straight lines c and d (Fig. 6-2) and c_1d and c_2d (Fig. 6-3). The action of the secondary regulator is effected through the speed changer. The change in the speed of the generating unit may be made dependent not only on the system frequency, but also upon other factors governing the operation of the secondary regulators, such as power flows over a transmission line or the total load of the power station.

6-3. Devices to Control Power Output

There are several ways of ensuring that the power system load variations are taken care of by separate generating units at one power station or a group of power stations.

(a) The characteristic $n = \varphi(P)$ of the generator responsible for handling the loads has the smallest steady-state coefficient (in the limit-transient characteristic). This generator is the pilot machine. The other supporting generators of the power station are equipped with devices which maintain the specified relation between their output and that of the pilot generator.

(b) The power station generators are included in the group control system with a central controller which controls the real power load of the whole power station. This controller is provided with frequency correction, i.e., it has a specified steady-state coefficient and its operation is limited when the frequency variations are more than ± 0.2 Hz beyond the rated value. The setting of the controller may be changed by attending personnel or by the power system central regulator.

The total output generation of the power station set by the power controller is allocated among the generating units in compliance with a preselected mode.

With generating units of the same type, for example, the load is uniformly shared by all the machines. When the machines are of distinct types, the load is so divided that in terms of reference fuel the relative incremental fuel consumption per 1 kW of extra generation is uniform (more exactly, uniform incremental expenditures of labour in terms of cost).

If the regulation is carried out by several power stations, each power station has its generation output set in compliance with its incremental characteristic. Using this scheme, centralized regulation of load frequency and real power at one low-rated individual power system and centralized operation of several power stations in one of the sections of the integrated power system in the USSR have been accomplished, thus making it possible to consider this part of the integrated power system as a single whole in relation to its participation in the common regulation system.

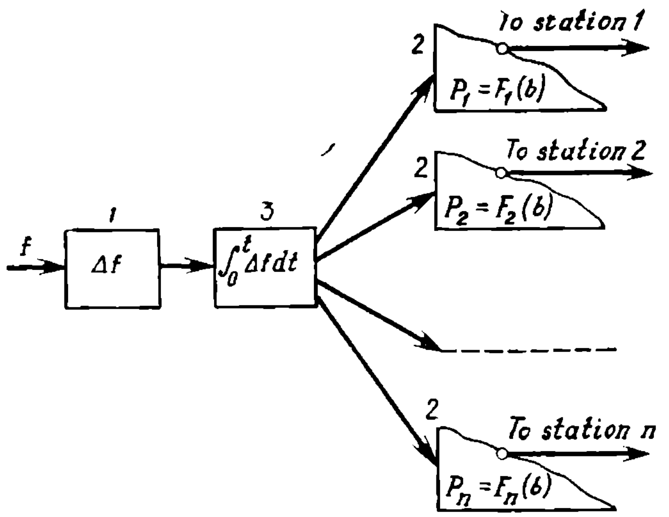


Fig. 6-4. Diagram of centralized frequency and power regulation

The schematic diagram of the scheme for centralized frequency and power regulation is shown in Fig. 6-4.

The central frequency and power regulator installed at the load-dispatching department contains:

(1) Measuring element *1* responding to changes in the frequency.

(2) Functional converters *2* which show how the load of each station involved in the regulation depends on the variable common to the entire system, in the function of which the load is allocated among individual power stations (for example, on the costs of generation or the relative incremental value in terms of reference fuel). The functional converters are shaped templates or shaped rheostats changing the input current of the remote control transducer.

(3) Integrating element *3* incorporating a reversible motor which actuates the converter systems when the frequency departs from the rated value until the frequency is reestablished to the normal value, thus transient frequency regulation is attained.

(4) Remote control equipment feeding the control signals to the power stations in compliance with the output pulses of the functional converters of the central regulator, i.e., in accordance with the required load of the power station.

At the power stations, the received signal acts on the local distributor which consists of a group regulation controller and a frequency corrector. The frequency corrector operates either continuously, creating steady-state conditions and frequency limitation or it only interrupts the action of the central regulator when the frequency departs from the preassigned limits. The frequency corrector also reduces the effect of false signals from the central regulator in

case of faults in the remote-control channels or when a power station with its area is separated.

In the apparatus put into service, provision is made for devices which allow the load settings to be changed manually. Use is also made of instruments indicating the load assignment sent to the stations.

(c) Distribution of the loads among the generating units of a power station and among the power stations taking part in the frequency and power regulawon is according to the incremental characteristics without communication bettieen the power station group controller and the central regulator effected

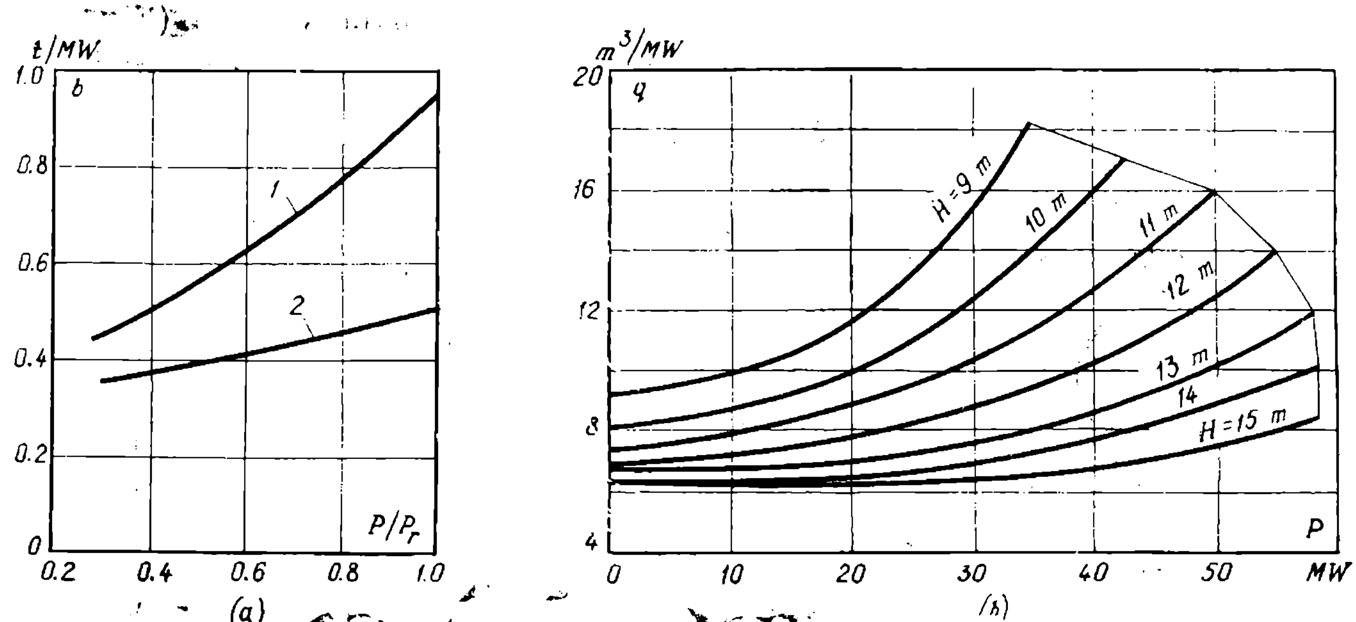


Fig. 6-5. Characteristics of relative increments
(a) fuel consumption; 1 — mean-pressure stations; 2 — high-pressure stations; (b) water consumption

through the remote-control devices. Frequency regulation is effected against the pulses generated by a synchronous time clock. If individual power stations are furnished with such clocks, there is no need (at the first sight) to use remote-control means. As mentioned previously, once the so-called decentralized AFPC system was suggested which, however, proved unfeasible as it was found necessary to take into account the losses in the networks which meant greater use of remote-control devices than in the case of the centralized AFP & FC systems. However, when use is made of group power regulation within a power station, the distribution of the load among the generating units relative to their incremental fuel consumption is rational especially when the regulation involves generating units of different types and capacities, a feature characteristic of some thermal stations.

Typical incremental fuel consumption curves *b* of thermal generating units and water consumption *q* at hydroelectric stations are shown in Fig. 6-5. By the incremental fuel consumption *b* is meant an increase in the consumption of reference fuel (in tons) per 1 MW increase in the generation. By the incremental

water consumption q is understood an increase in the water supply (in cu.m) per 1 s, when the generation is raised by 1 MW. With the hydroelectric generators b is assumed to equal λq, where λ is a conversion factor to be used in recomputation of the characteristics.

It is seen from the characteristics shown in Fig. 6-5 that an increase in the steam supply to the turbine, or water to the hydroturbine causes an increase in fuel (water) consumption. The incremental consumption transducer takes this regularity into account. The following principle underlies the transducer operation.

A synchronous motor connected to the power system voltage (Fig. 6-6) actuates the hand of the electrical clock. If the power system operates at the

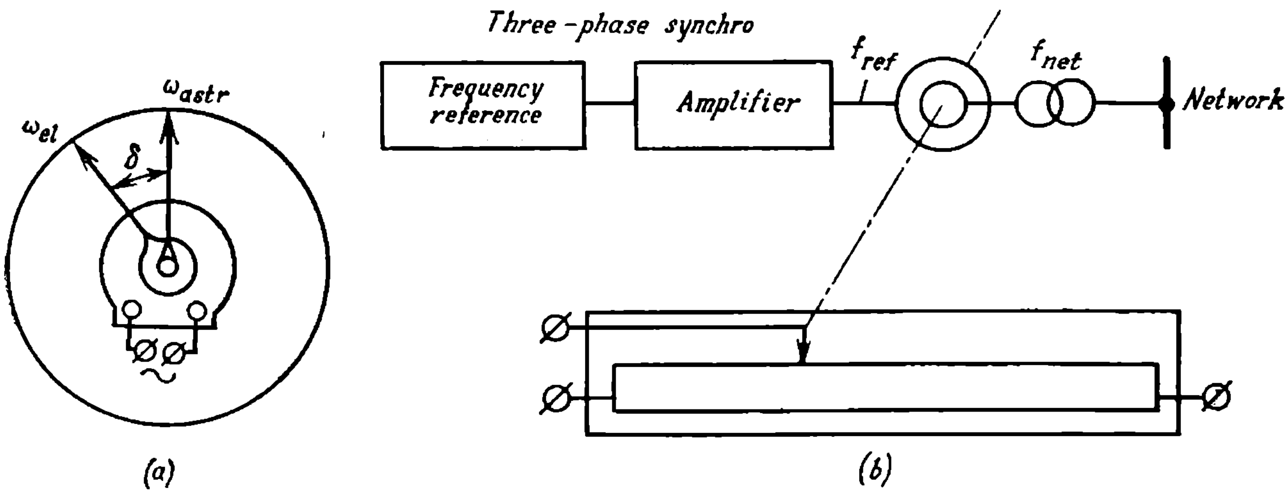


Fig. 6-6. Operation of frequency regulator based on comparing astronomical and electrical time

(a) explanatory diagram; (b) integrating element diagram

rated frequency, the hand of the electrical clock and the hand of an exact astronomical clock will coincide. When the frequency departs from the rated value the clock hands become separated by an angle δ. The longer and greater the frequency departure, the greater the angle deviation between the hands

$$\delta_t = \int_0^t \Delta f \, dt \tag{6-3}$$

The value of angle δ_t is determined by the difference between the astronomical time

$$T_{ast} = \eta \int_0^t f_{ref} \, dt \tag{6-4}$$

and the synchronous time

$$T_{syn} = \eta \int_0^t f_{syn} \, dt \tag{6.5}$$

where f_{ref} = reference frequency value
f_{syn} = system voltage frequency
η = proportionality factor

From (6-3) to (6-5) it follows that

$$\Delta T = T_{ast} - T_{syn} = \eta \int_0^t \Delta f \, dt = \eta \delta_t \tag{6-6}$$

It is clear from the last expression that a decrease in the frequency increases the difference between the astronomical and synchronous time. Thus, this difference qualitatively is similar to the changes in the relative incremental fuel (water) consumption per unit time and may serve to a degree as a criterion of the regulation system. The principles underlying the device comparing the electrical time with the astronomical time and the design of the device integrating element are illustrated in Fig. 6-6*b*.

6-4. Power Group Control at Thermal Stations

Automation of the power generation process at the power stations with individual boiler-turbine-generator units (at present, most of the power is generated by such units) provides automation of operation of each unit in accordance with the specified generator load, and economical allocation of the load assigned to the given power station among the individual units.

The group of devices which automatically regulate the steam input to the turbine, depending on the resistive load of the generator, utilizes the mechanical or electromechanical governor of the turbine, which is coupled to the controller of the group control system, and the regulators, often electronic, which operate the boiler mechanisms so that the steam parameters (pressure and temperature) at the turbine input are held at their optimal values corresponding to the generator load.

To optimize the operating conditions of the generating units, some electrical power stations use electronic computers.

Regulation on the basis of maintaining the relative fuel consumption constant or, with individual units of the same type, on the basis of ensuring the maximum station efficiency as a whole, allows the loads to be economically allocated among the individual units without much difficulty.

Figure 6-7 illustrates the schematic (block) diagram of a regulating circuit. The relative increment of the power station is set manually or this is accomplished by an overall regulating device which takes network losses into account.

Regulation of operation of a unit with a monotube boiler is effected through the air regulator which controls the firing and steaming rate of the boiler. The control pulse to the air regulator is shaped in a summator which adds and amplifies the signals from the turbine inlet steam pressure gauge, the real power meter of the generator, the frequency variation meter and the resistive load allocation device.

The pressure transducer generates its output signal until the steam input parameters are worked out by the pressure regulator. These parameters should correspond to the required pressure which must be ensured by the regulator. When the pressure drops to a value dangerous to the turbine operation, the safety means come into action and disconnect the unit.

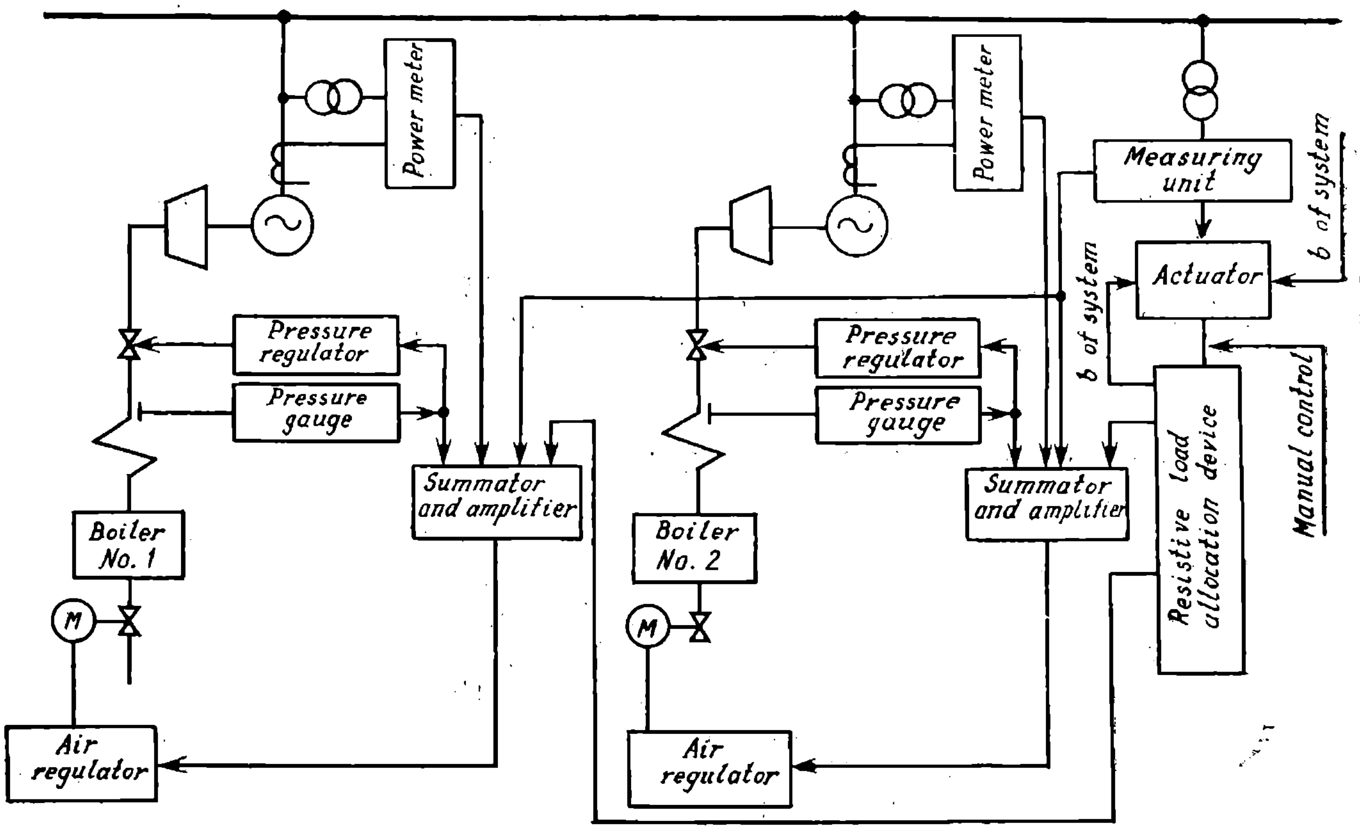


Fig. 6-7. Schematic diagram of frequency and power automatic regulation at thermal station with individual boiler-turbine-generator units

The output signal from the resistive load allocation device is being fed to each unit, with due consideration to the relative incremental fuel consumption characteristic, until the relative incremental consumption b_{st} of the station and the output signals from the devices producing the data on the value of relative increase in the fuel consumption in terms of reference fuel b_{sys} of the power system with the losses in the networks taken into account are balanced. The position of the load allocation device and the power setter may be controlled manually (from the group control station switchboard) or by the device making the station follow the specified operational load schedule, by a computer or by the central regulator of the power system.

6-5. Power Group Control at Hydroelectric Stations

At thermal stations the shutdown generating units cannot be immediately involved in regulation of frequency and real power, since it takes much time to bring the boiler and turbine into operation from cold.

The best flexibility in regulating the frequency and power is provided by the hydroelectric generators. At hydroelectric stations with one-type machines it is fairly easy to effect a group control system and ensure the automatic connection of shutdown units to it.

The service regulations state that in case of a frequency fall in the power system provisions be made for automatic connection of the shutdown hydroelectric generators (frequency starting) and change-over of the hydroelectric generators used as synchronous capacitors to power generation duty, the settings of the automatic controls being 48.8 to 49.7 Hz.

Figure 6-8 illustrates a circuit for automatic connection of hydroelectric generators in case of a frequency fall in the power systew.

The starting of individual units (or groups of generators) is provided from a programming time relay. By means of operation keys each generator is connected to the busbars of the required sequence. The sequence time intervals are selected either to prevent simultaneous connection of the generators (several seconds) or to prevent connection of the generators next in sequence (1-2 min), if the frequency is recovered after the foregoing machines have been connected.

The starting automatic controls are turned on by the underfrequency relay *FR*. The time to send a pulse to connect the first sequence group of generators is determined by the setting of relay *1TR* having an 0.5 s delay which prevents the device from functioning at random short-time closures of the underfrequency relay contacts, like in the case of voltage surges and at synchronous swings.

The time relay *1TR* is thermal resistant. In operation, its instantaneous contacts *1TR-1* open and a series resistor is connected in series with its coil. The contact *1TR-2* closes an auxiliary relay *1AR*. The latter in turn makes the circuits of a sequence-action time relay *2TR* and with its contact *1AR-3* feeds the operating current to the first-sequence automatic starting bus. The sequence-action relay *2TR* determines the intervals at which the next of the machines in the sequence will be turned on. The intervals Δt between the control pulses are preadjusted by setting the programming relay within the range of 10 to 120 s. The machines are connected sequentially at different intervals by means of operation keys *OK* and auxiliary relays *UFR*. The contacts of these relays close the automatic starting circuits of the corresponding machines.

The sequence in which the various devices are used in connecting the hydroelectric generator for parallel operation is shown in Fig. 6-9.

In case of an emergency fall in the frequency, the starting device of the hydroelectric generator may function in conjunction with an automatic operator, if it is available at the hydroelectric station.

The automatic operator promotes timely connection and disconnection of the generating units in the process of frequency, real power and power flow regulation as dictated by the changes in the station load (according to the load schedule) or the most economical requirements of the water flow determined by a load setter (an electronic computer in this case).

The general requirements to the automatic operator equipment are as follows:

1. The hydrogenerators are started and shutdown as dictated by the water

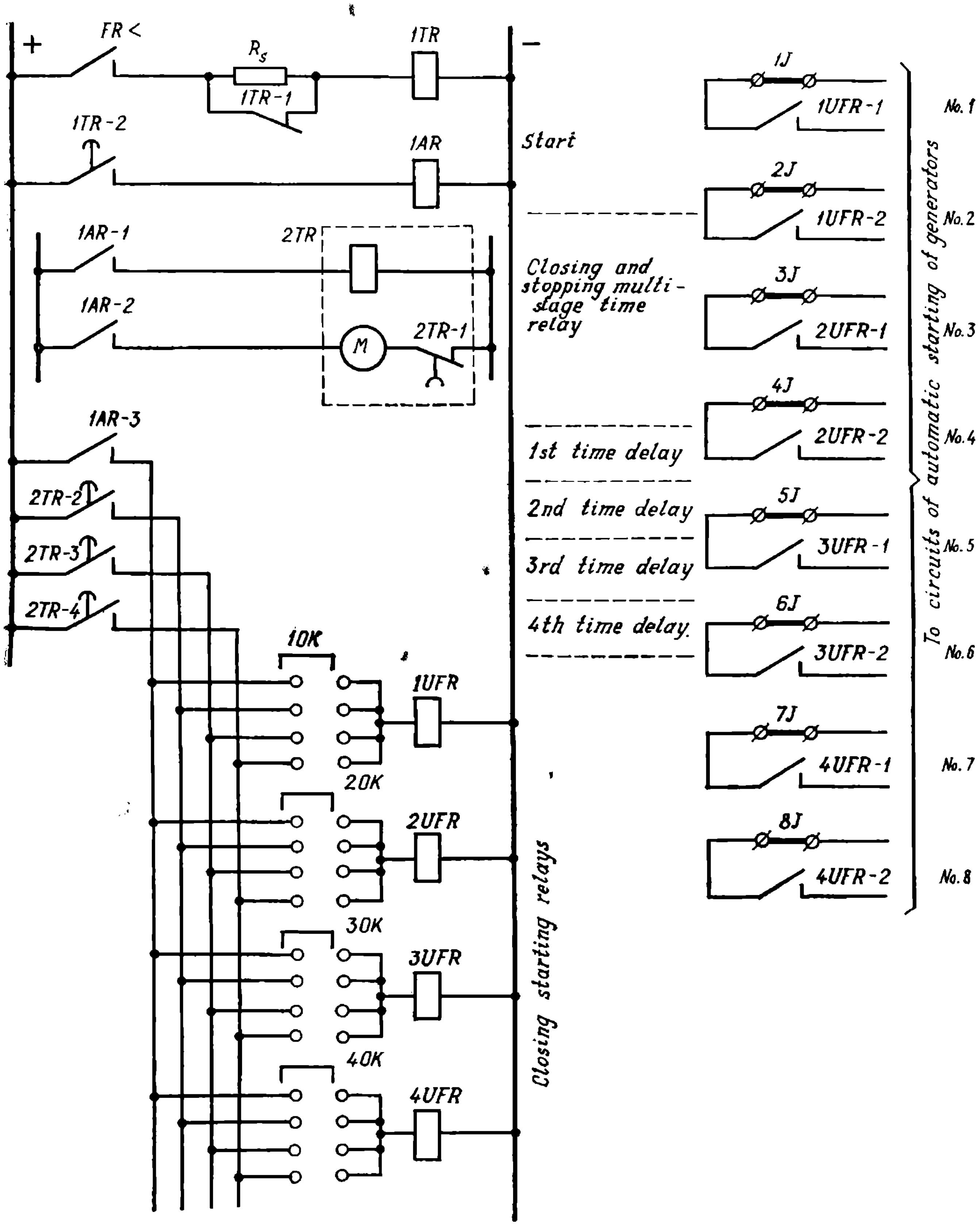


Fig. 6-8. Automatic connection of hydroelectric generators when power system frequency falls

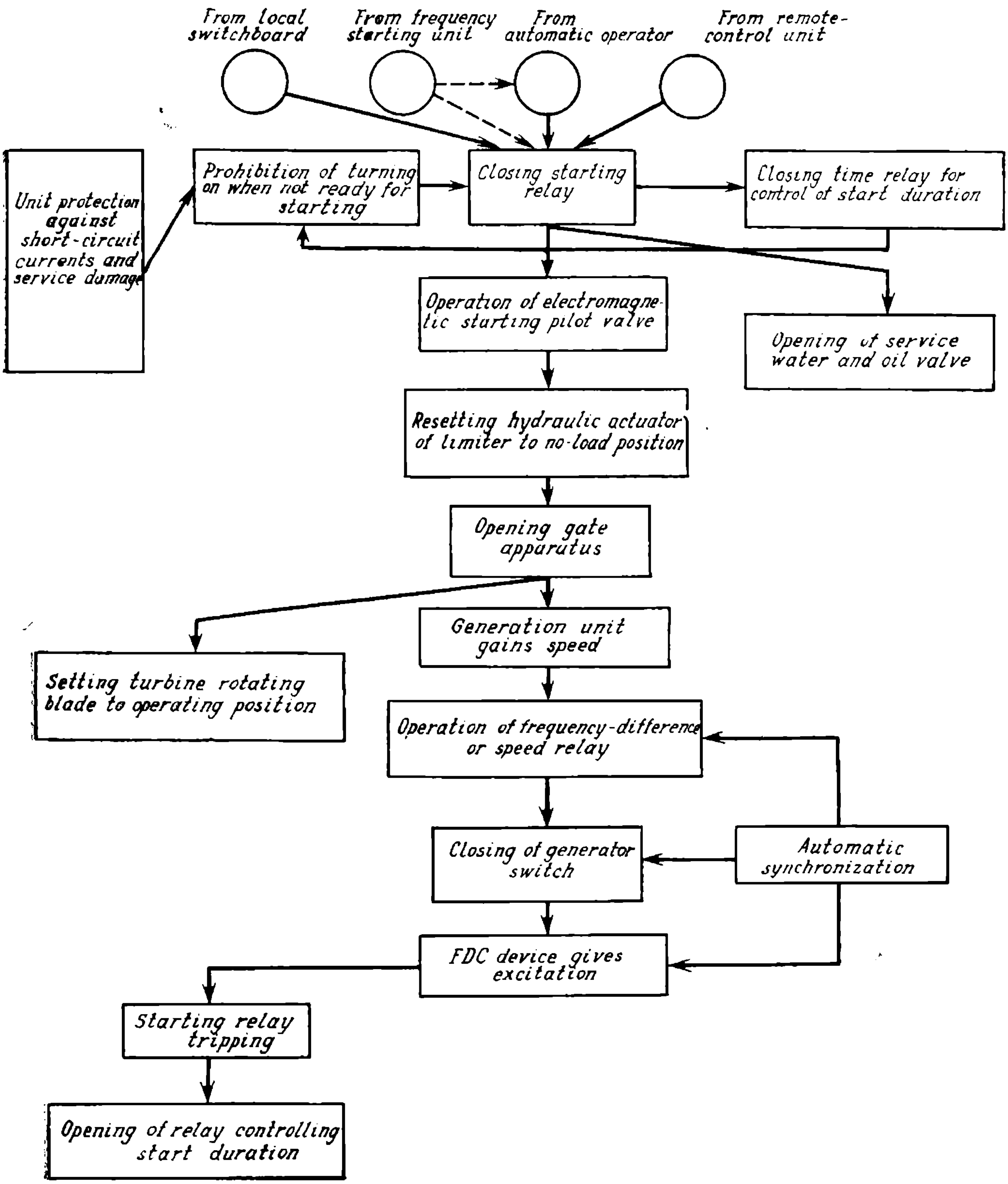


Fig. 6-9. Suggested sequence of operations in automatic starting of hydroelectric generation unit

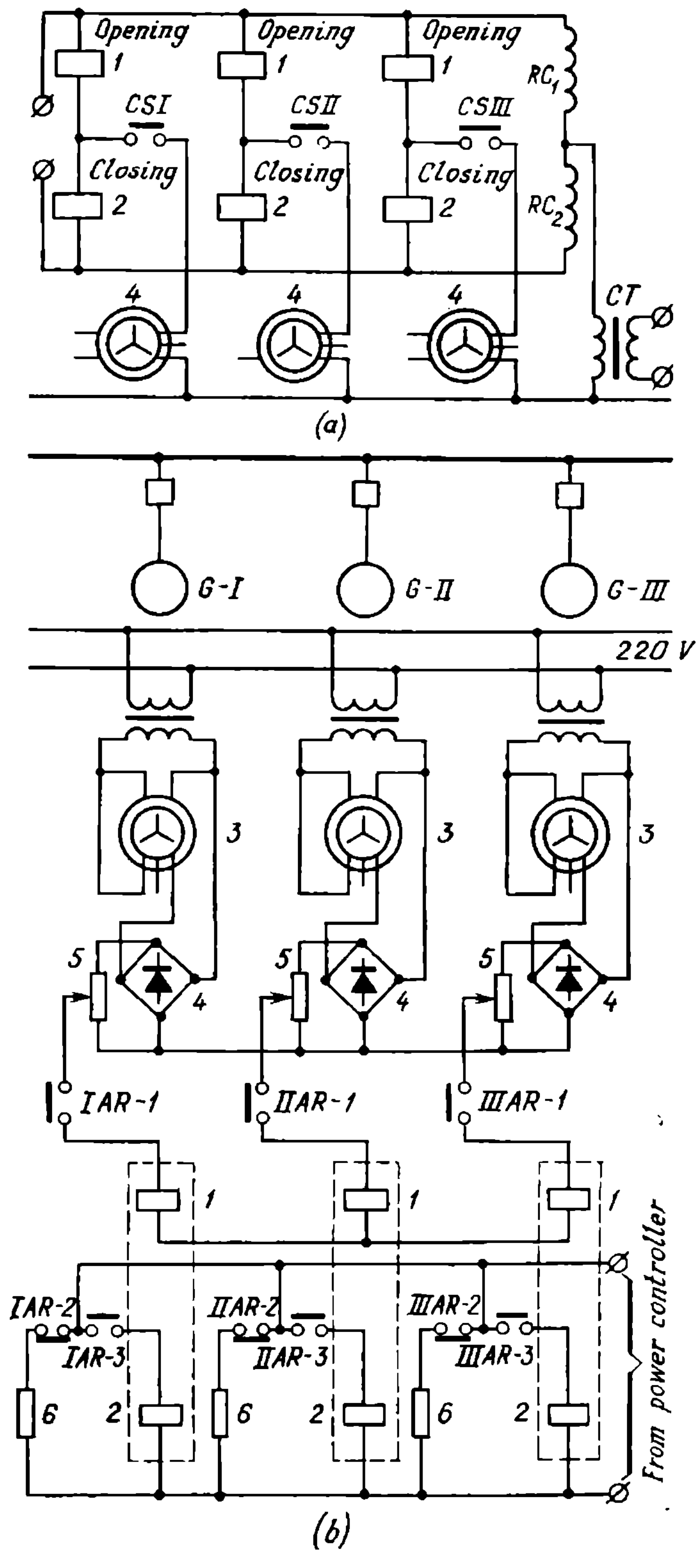


Fig. 6-10. Group speed regulation with **hydro-electric** correctors

(*a*) a.c. supply to corrector; (*b*) d c supply **to** corrector

head and load of the working generators so that the most economical working of the entire power station is achieved (with due considerations to the method of equal relative increments and losses in the transmission lines) and that the specified amount of spinning reserve is ensured.

2. When the power system frequency falls below the rated value automatic actions must be effected to start the stand-by generators and to change over the generators operating as synchronous capacitors to the generation duty.

3. The first generator of the stand-by units in the sequence shall be started when one or more of the working generators are disconnected due to a fault, or when a hydrogenerator is disconnected from the group automatic regulation system for some other reason than the automatic operator's action.

4. When the power system frequency drops, the group control device (the load controller) shall be automatically acted upon so that all the generating units controlled by this device take a maximum resistive load even if it exceeds the value preassigned by the load schedule.

Diagrams explaining the principles underlying the group power regulation of the power station units are given in Fig. 6-10.

Control solenoids *1* and *2* of the hydroelectric correctors of the hydroelectric turbine primary speed governors are connected so that when the current flows in the solenoid coils are balanced, the oil system of the corrector is turned off, i.e., the oil flow ports are closed.

If the current flow in coil *2* is greater than that in coil *1*, the oil system of the corrector actuates the booster lever of the primary speed governor to close the gate apparatus. The reverse takes place, when the current flow in coil *1* is greater than the flow in coil *2*. The degree to which the gate apparatus is opened is controlled by synchros operating as transformers. If an alternating current voltage is applied to the rotor coil of such a synchro, the emf at the output of the stator coil will change when the rotor turns.

The use of synchros makes it possible to install the equalizing circuit at the central control station and utilize small gauge connecting cables.

In the circuit shown in Fig. 6-10*a* each synchro *4* is connected into the equalizing circuit through a control switch *CS* of the machine involved in the automatic group control. Under normal operating conditions the torques of solenoids *1* and *2* are balanced. If one of the machines has changed its load, the spatial position of the synchro rotor will change and an additional emf will appear across the stator output.

Relative to the voltage vector feeding the equalizing device, the additional emf will be of different phase shift, depending on the position of the gate apparatus. As a result, the current will rise in coil *2* of the governor corrector of the generator which was the first to take the incremental load. Accordingly, the current in coil *1* will decrease and the gate apparatus will start to slowly close. As this happens, the current flow in coils *2* of the correctors of the speed governors of the other generating units will decrease, while that in coils *1* will increase and the gate apparatus will start to open gradually.

Data on the effects of external factors (total load of the station, power flows and the like) may be introduced in the regulating process. To this end use is made of an intervening coupling transformer *CT*, the secondary emf of which is fed to the equalizing circuit via reactance coils RC_1 and RC_2.

With the hydroelectric speed governor correctors employing solenoids *1* and *2* made as d.c. electromagnets (Fig. 6-10*b*), the output voltage of synchro *3* depending on the position of the gate apparatus is rectified by rectifiers *4* and fed to the equalizing circuit through variable resistor *5*. Operation of the device is similar to that of the corrector described above. Control coils *1* and *2* of the speed governor hydroelectric corrector of each machine participating in the group regulation are connected to the equalizing circuit by auxiliary relays *AR*.

In order to avoid readjusting the group control device, when one of the machines is tripped, ballast resistor *6* is cut in by auxiliary relays *AR*, the contact position of which depicts the operating state of the machine.

6-6. Frequency and Power Control in Integrated Power Systems

When designing integrated power systems, the operation of AFP&FC devices is considered as part of the automatic load-dispatching process.

As intimated above, the performance of a power system is determined by correct forecasting and assigning the loads, by considering the power resources

available and the condition of equipment (in particular, the maintenance it needs) weather conditions (lightning storms, high winds, ice and sleet storms,

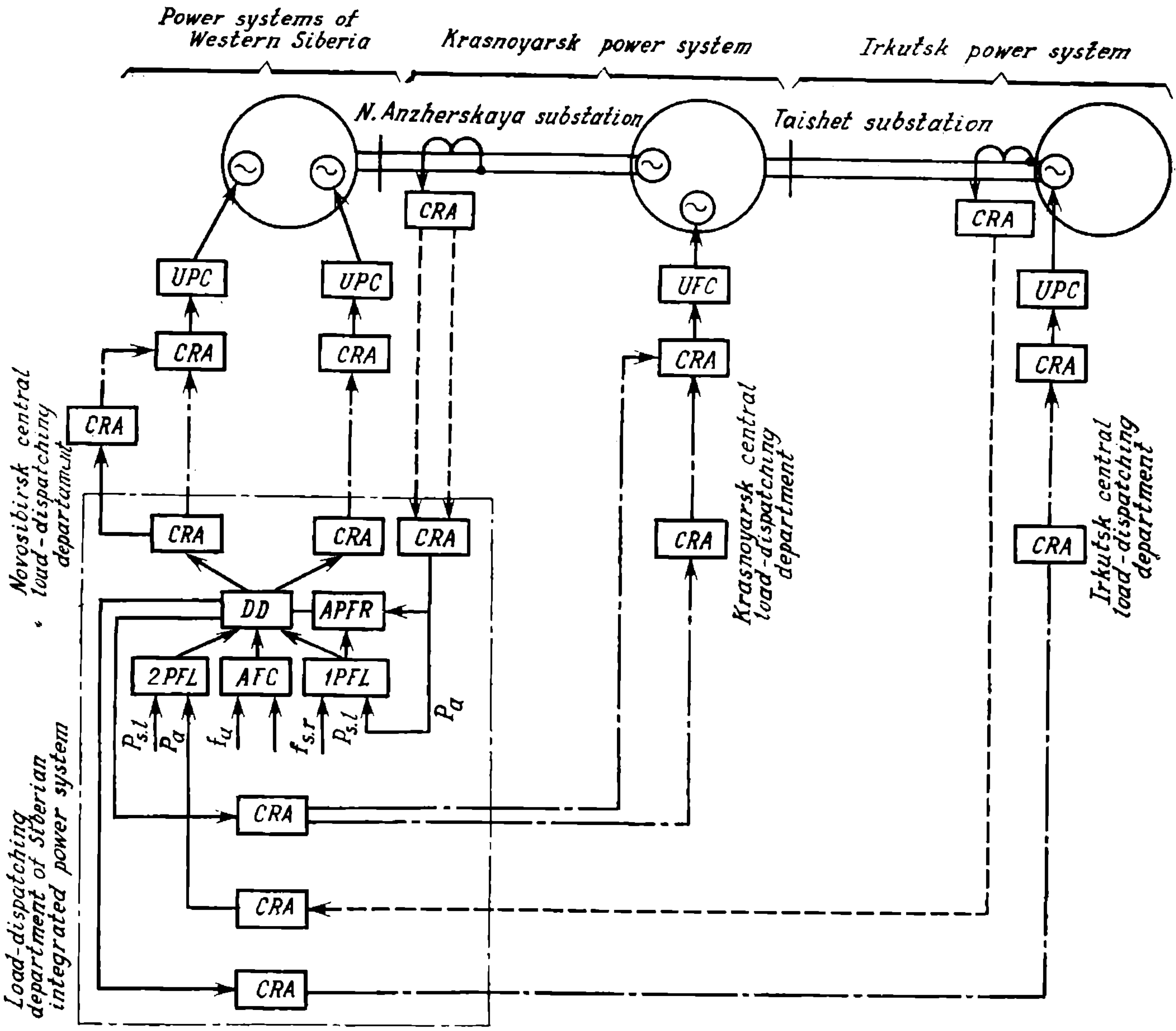


Fig. 6-11. AFP&FC in Siberian integrated system

AFC — automatic frequency control regulator; *APFR* — automatic power flow regulator; *1 PFL* and *2 PFL* — 1st and 2nd real power flow limiters; *DD* — unscheduled power distributing device; *UPC* — unscheduled power controller; *UFC* — unscheduled power flow controller; f_a — actual frequency; $f_{s.r}$ — specified frequency; P_a — actual value of real power flow; $P_{s.r}$ — specified setting of regulated flow of real power; $P_{s.l}$ — specified setting of limited flow of real power; *CRA* — communication and remote-control apparatus; the broken lines show remote measuring channels. The dash-and-dot lines show remote-control channels

maximum and minimum temperatures, etc. for all areas), the situation with water and fuel, determining their consumption rate (i.e., decrease in generation output from power stations operating on coal, gas, oil); ensuring a certain power output by different power stations (for example, heating and power

plants, atomic power plants, high-pressure stations with generating units providing stable operation only at constant load parameters), etc.

The above circumstances are taken into account when preparing 24-hour load schedules for the integrated power system as a whole, individual power systems, individual power stations and for the power flows over the main tie lines. These days computers are used to prepare daily loading schedules.

With proper planning and load allocation, frequency changes in integrated power systems are minute and the frequency control can be allocated to either a group of small power stations or one large-rated power station.

The "optimization" task is then reduced to remedying unplanned load variations.

An integral part of the system regulation scheme in a large power engineering centre is a periodically operating flow regulation system, since unplanned changes in the load may first of all affect the intersystem and system links. In the complex power engineering centers, the flow regulation must be controlled from one centre by a logic device redistributing the specified load among the power plants in order to prevent disturbances to the tie-line stability. At present, this problem is not yet fully solved.

It was proposed that the duty of handling unscheduled real load variations which generally did not exceed 2 to 3 per cent could be fulfilled by the AFP & FC system in the integrated power systems so that the specified schedules could be executed by local personnel manually or, which was much better, through the group control system. The controllers of these systems fulfil the specified load schedule with the required corrections in the frequency and power flows over the branching transmission lines.

Figure 6-11 shows the block diagram of an AFP & FC circuit used in the Siberian integrated power grid which includes the Nazarovsk, Novosibirsk and Bratsk electric power stations, the central load-dispatching departments of the Novosibirsk, Krasnoyarsk and Irkutsk power systems and the load-dispatching department of the Siberian integrated power grid [6-6].

The following duties are automated:

1. Frequency regulation by the criterion

$$K\int_{t_0}^{t_1} \Delta f\,dt + \sum \Delta P_{st} = 0 \tag{6-7}$$

by means of a frequency regulator.

2. Regulation of the intersystem real power flow over the 500 kW transmission line from the Nazarovsk power station to the Novo-Anzherskaya substation by the criterion

$$K\int_{t_0}^{t_1} \Delta P_{fl}\,dt + \sum \Delta P_{st} = 0 \tag{6-8}$$

with the aid of a power flow regulator.

3. Combined regulation of the frequency and intersystem power flow over the transmission line from the Nazarovsk power station to the Novo-Anzherskaya substation with simultaneous operation of the frequency regulator and the power flow regulator by the criterion

$$K\int_{t_0}^{t_1}\Delta f\,dt+KK_c\int_{t_0}^{t_1}P_{fl}\,dt+\sum\Delta P_{st}=0 \tag{6-9}$$

4. Frequency regulation with a specified allocation of unscheduled power among the receiving and sending parts of the power system by the criterion

$$K\int_{t_0}^{t_1}\Delta f\,dt+KK_cK_{unsch}\Delta P_{fl}+\sum\Delta P_{st}=0 \tag{6-10}$$

is accomplished by the simultaneous operation of the frequency and power flow regulators.

Power flow is limited by limiters *1PFL* and *2PFL* which function when the actual power flows (P_a) over the lines under supervision exceed the rated values corresponding to the settings ($P_{s.\,l}$), i.e., when $P_a > P_{s.\,l}$.

When an output signal is available, the power flow limiter operates as a regulator by the criterion

$$K\int_{t_0}^{t_1}\Delta P_{fl(0)}\,dt+\sum\Delta P_{st}=0 \tag{6-11}$$

performing transient regulation of the critical specified power flow over the transmission line, i.e., when $P_a = P_{s.l}$.

When the causes of the line overload disappear, the limiters reset and the power stations involved in the regulation automatically return to the power scheduled operation.

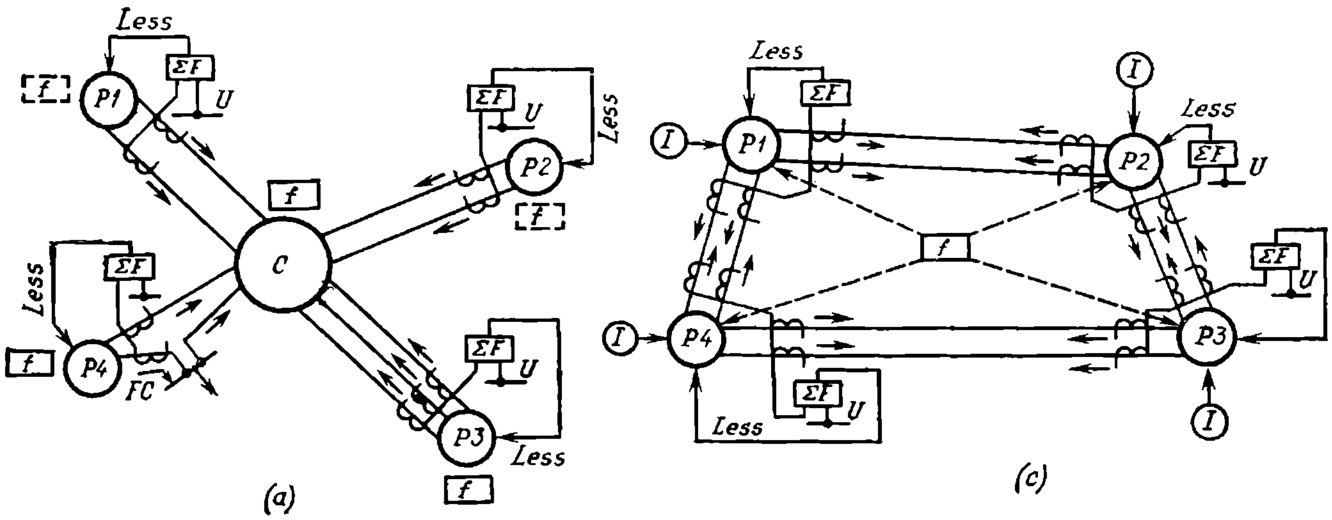
In expressions (6-7) through (6-11) Δf, ΔP_{fl} and $\Delta P_{fl(0)}$ are departures of the actual values of frequency and power flows from those given for regulation and limitation of settings ($\Delta f = f_{op} - f_{s.r}$; $\Delta P_{fl} = P_{fl} - P_{s.r}$; $\Delta P_{fl(0)} = P_a - P_{s.l}$); $\Sigma\Delta P_{st}$ is the total unscheduled power of the regulating power stations; K is a coefficient; K_c is a circuit coefficient; K_{unsch} is a coefficient determining the allocation of unscheduled power among the power stations of the sending and receiving parts of the integrated power system.

The regulating system ensures unloading of the transmission line by $\Delta P_{fl} = 0.6\ (P_a - P_{s.l}) = -(60\text{-}100)$ MW in the aperiodic process of power flow limitation with a time constant of 15 to 20 s and suppression of power flow swings having a cycle of 2 to 3 minutes. The power flows are maintained by the frequency and power flow regulators astatically within a period of 15 to 20 min.

To prevent misoperation of the regulation system in case of equipment faults and isolation of some parts of the 500-kV transmission lines, protection and interlocking systems which send alarm signals to station personnel are provided.

When installing the AFP & FC devices in integrated power systems the following must be taken into account.

(a) The central power system C is connected with periphery power systems P by limited capacity tie lines. Power drawn off by the intermediate substations



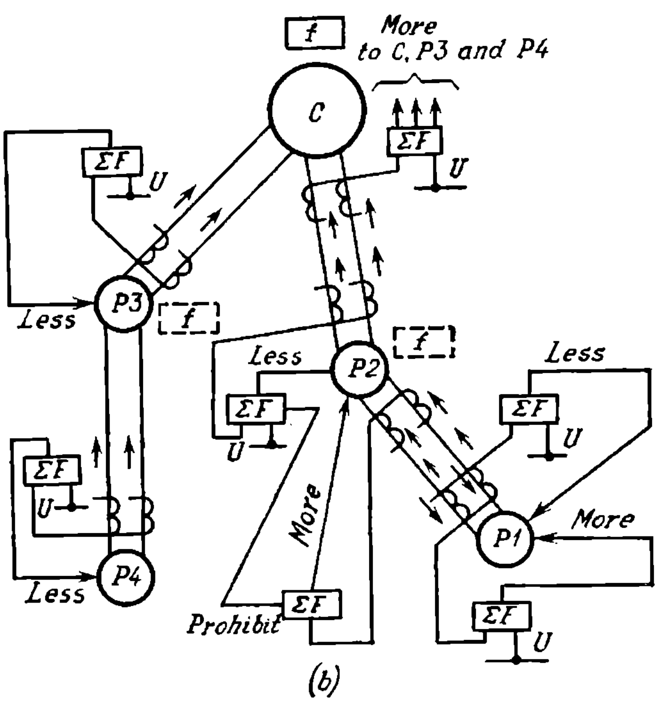


Fig. 6-12. Examples of combining individual power systems into integrated power system
(*a*) by radial peripheral tie lines (*FC* — correction of critical power flow ΣF by section flow); (*b*) with tie lines through intermediate power systems (in tie line *P1-P2* real power flows may be either from *P2* to *P1* or vice versa); (*c*) by ring tie links (1 — unloading internal tie lines being overloaded)

of these tie lines has no perceptible effect on the critical permissible value of real power flows (Fig. 6-12*a*).

Unscheduled changes in the loads make the frequency depart from the rated value. The primary speed governors of all paralleled generators, frequency correctors of the group control devices of power stations and the central frequency regulator of the integrated power system respond to these departures. Under the action of these devices the load is to some degree redistributed and

the power station generators intended to handle the unscheduled variations of the load are switched in by the central frequency regulator having the least steady-state stability, the load sharing being as preassigned.

An increase in the generation of the outlying power systems caused by the action of the frequency regulator may result in a dangerous overload on certain tie lines. Overloading may also occur if the central power system undergoes a lack of power due to disconnection of its generators or one of the outlying tie lines supplying the centre. The outlying tie lines can be kept in operation and the generation output of the integrated power system used to the maximum by timely unloading of the overloaded tie lines and prevention of real power flows over these lines in excess of the permissible values.

This limitation is accomplished by the power flow limiters installed on the tie lines. The limiters perform unloading operations, if necessary. With the network shown in Fig. 6-12*a* power flow limitation is obtained by automatic reduction of the output of the power stations (or one station used for the purpose) of the periphery power system supplying the overloaded tie line.

The setting of the group regulator power controller is controlled by the power flow limiter. The control signal is transmitted with the aid of remote control devices or by local control means.

(b) The central power system C is connected to the peripheral power systems as shown in Fig. 6-12*b*, the peripheral power systems being series-connected to each other ("chain" scheme).

Limitation of power flows in the terminal ties should be performed by the limiters installed on the tie lines so that the unloading of the assigned power stations is effected in the terminal power systems, depending on which of the tie lines is overloaded.

Over the tie line $P1$-$P2$ real power can be transmitted from power system $P1$ to $P2$ and vice versa.

When power flows from $P1$ to $P2$ over the $P1$-$P2$ tie line the real power flow may be limited by increasing the generation of $P2$. This, however, may be permitted only if the C-$P2$ tie line is underloaded and will not be overloaded after the power stations of system $P2$ raise their load. This condition is assured by introduction of prohibitive blocking from the $P2$-C tie line power flow limiter.

Removing a dangerous power flow over the $P1$-$P2$ tie line can be made by the central regulating device which receives information about the loads on individual parts of the tie lines from the remote control channels. For example, the $P2$-C tie line may be unloaded by increasing the loads on the power systems $P3$ and $P4$.

The fulfilment of such a "thinking" automatic device in the central regulator complicates the design and in the cace of very complicated circuits a computer is needed to determine the required load with minimum losses. In the first stages of establishing an automatic power flow limiting system a simple version should be designed. Later, this simple version may be used as a back-up one.

When no "thinking" automatic device is available in the central regulator, the required operations for increasing the load of the intermediate power systems

in order to reduce the power flows between these systems and the terminal peripheral systems are performed on the order of the central dispatcher or by local personnel on their own from instrument readings. To prevent dangerous overloads, the intermediate tie lines should be equipped with limiters to separately check the total amounts of incoming and outgoing real power. The limiters unload the intermediate power system stations when the tie line over which power flows to the central system is overloaded, or loads these stations when the tie line with incoming real power is overloaded while the tie line with outgoing real power is underload.

A limiting system utilizing the above-described principle is operating in the power grid of the European part of the USSR on the Centre—Lenin Volga hydraulic power station—Ural tie line.

After accomplishing the local limiting power flow systems on the intersystem tie lines, the frequency regulation may be placed with the central regulator without the risk of dangerous overloads. When unscheduled real power variations occur, the central regulator activates the generating units of the regulating power stations (directly or through the centralized control devices of individual systems contained in the integrated system), while the other power plants continue to follow the assigned schedule.

The task of the load-dispatching personnel engaged in operating the system is to ensure a needed real power spinning reserve at the regulating (pilot) power station and that the flow of that power over the transmission lines is not blocked.

(c) The integrated system is obtained by ring connecting individual regional power systems. The central AFP & FC regulator is installed at the load-dispatching department of the integrated power system (Fig. 6-12*c*) and it can control the regulating power stations in each of the power systems (directly or through the AFP & FC devices installed at the load-dispatching departments). The load share is set by the central dispatcher with regard to the operating conditions of the integrated system and individual power plants.

The assignments worked out by the central regulator are then corrected and limited to the real power flow values of the intersystem tie lines. The total incoming and total outgoing real power is considered (balancing of the power flow) as well as the critical real power flows permissible over certain tie link sections.

Real power flow limiters should be also provided to unload the internal ties by removing the load from individual power plants of the given power system. The best results are obtained by changing the real power value at the power plants electrically close to the overloaded transmission lines. At the present time the AFP & FC system in the ring integrated power systems is being studied. Therefore, the above should be regarded as a version to be verified and studied additionally. Some organizations plan to use a high-speed electronic computer for the AFP & FC devices of this integrated power systems with remote-control data input and control pulses output.

6-7. Magnetic Power Transducers

An essential component of the AFP&FC devices is a real power transducer. A magnetic power transducer with no moving parts performs well and reliably. For the circuit of such a transducer see Fig. 6-13. The current flows in the rectifiers *7RB* and *8RB* are proportional to squares of voltages U_4 and U_5, i.e., $i_1 = \gamma U_4^2$ and $i_2 = \gamma U_5^2$, owing to the nonlinear

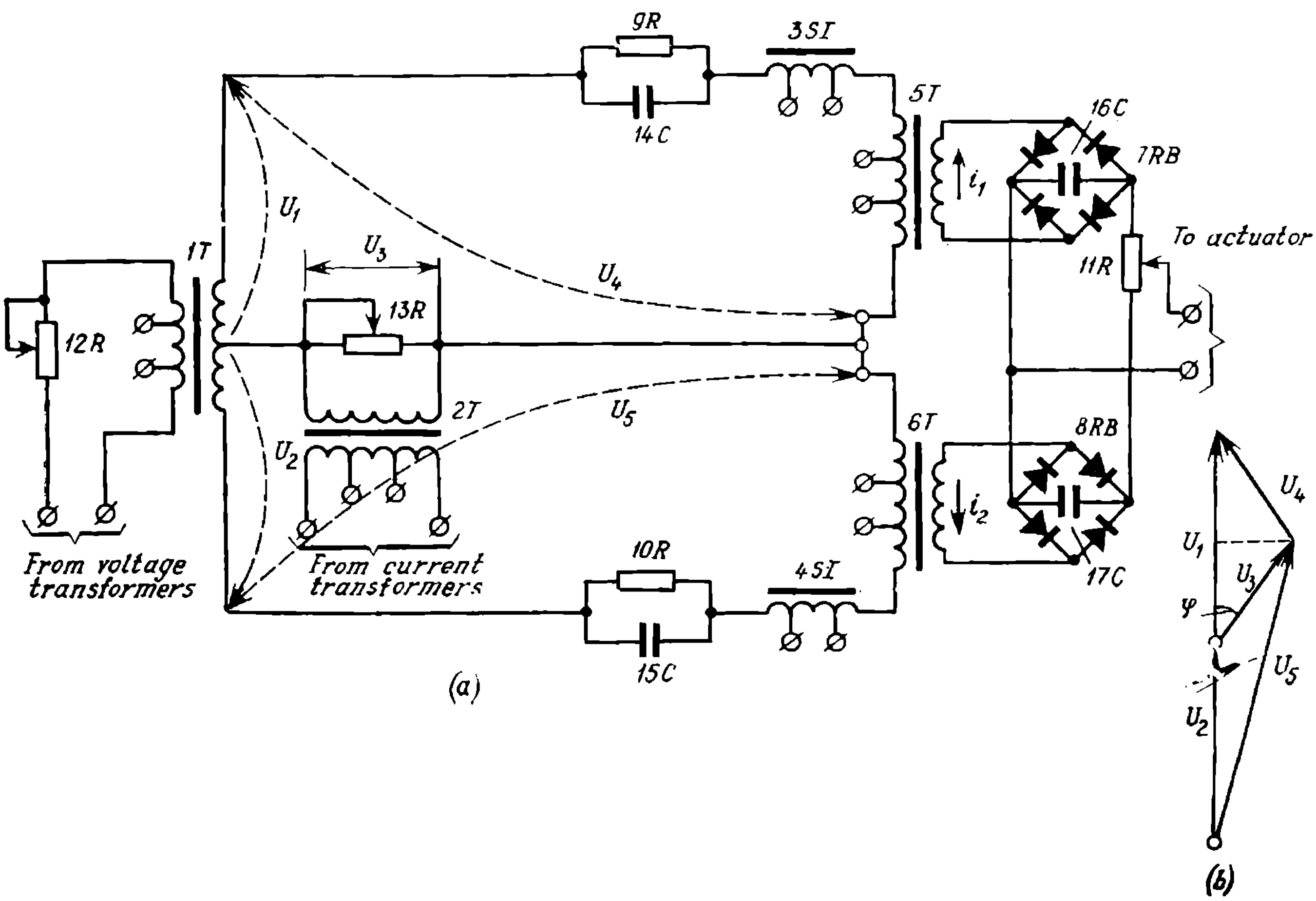


Fig. 6-13. Magnetic power transducer

(*a*) circuit; *1T*, *2T*, *5T* and *6T* — intervening transformers; *3SI*, *4SI* — saturable inductors; *7RB* and *8RB* — rectifying bridges; *9R*-*13R* — series resistors; *14C*-*17C* — capacitors; (*b*) explanatory diagram; $U_1 = U_2 = \alpha U_{AB}$; $U_3 = \xi I_A$

characteristics of the saturable inductors *3SI* and *4SI* and also to the choice of resistors *9R*, *10R* and capacitors *14C* and *15C* at the output of the intervening transformers *5T* and *6T* of the phase-sensitive circuit.

From Fig. 6-13*b*

$$U_5 = \sqrt{(U_2 + U_3 \cos\varphi)^2 + (U_3 \sin\varphi)^2} \quad (6\text{-}12)$$

and

$$U_4 = \sqrt{(U_1 - U_3 \cos\varphi)^2 + (U_3 \sin\varphi)^2} \quad (6\text{-}13)$$

The resultant effect of the power transducer at the input of the actuator unit is determined by the resultant current

$$I_{res} = i_2 - i_1 \quad (6\text{-}14)$$

Since $i_1 \equiv U_4^2$; $i_2 \equiv U_5^2$; $I_A \equiv U_3$; $U_{AB} \equiv (U_1 = U_2)$
then

$$I_{res} = k_1 [(U_2 + U_3 \cos \varphi)^2 + (U_3 \sin \varphi)^2 - (U_1 - U_3 \cos \varphi)^2 - (U_3 \sin \varphi)^2]$$

i.e.

$$I_{res} = kU_{AB} I_A \cos \varphi$$

where k is the proportionality factor which is controlled by tap changing on the intervening transformers *1T*, *2T*, *5T* and *6T*.

6-8. Conclusions

1. Automatic control of frequency and real power improves the power quality and makes economic loading of the generating units possible. This control is feasible, if a spinning reserve of real power in the power system is available and the tie links have sufficient transmission capacity so that the use of this reserve is not hindered.

2. The primary speed governors of the turbines installed on each generator-turbine unit are essential operating elements of the generating units and ensure their operation in case of changes in the electrical load of the generators. The primary speed governors (generally centrifugal) act on the steam (water) supply to the turbine via a speed changer and determine the primary regulation characteristic, i.e., the dependence of speed on load.

3. For the generating units furnished only with primary speed governors and not included in the group control system, the share in handling the changes in the external load is inversely proportional to the steady-state coefficient of the regulation characteristic. If the generating units are included in a group control system the load may be properly allocated by actuating the electrohydraulic or electromagnetic correctors provided in the primary speed governing devices.

4. When a spinning reserve of real power is available in a large power system the frequency is held stable at the nominal level by the combined action of the primary speed governors of the paralleled generating units. The larger the rating of the power system, the less the frequency hunting about the mean value.

5. When the machines of a multi-unit power station have a group control system the given power station may be considered in the AFP & FC system as a united whole. The load is allocated among the generating units either by the equalizing system with a preassigned share of each machine in the total generation or on the basis of equalizing the incremental fuel consumption (costs) per 1 kW of generation.

6. The operating conditions of a power station with a real power group control system depend on the power controlled setting. This setting is accomplished either according to a prescribed schedule or is assigned by the duty personnel. The assigned values are corrected by the frequency corrector which determines the relation $f = \varphi(P)$ for the given power station, the losses in the networks delivering power to the power system also being taken into account.

7. At the thermal stations the operation of the real power group control devices should be coordinated with that of the automatic heat control devices. The electrical load of a generator must not be higher than the turbine entry steam pressure. When the load suddenly drops the automatic safety devices should not function and the generating unit must continue to operate (within the range from idling to supplying the house circuits of its own power station).

At the power stations responsible for district heating the AFP & FC devices should not interfere with the normal heat supply.

8. At the hydroelectric power stations, the work of the AFP & FC devices should be combined with the action of the automatic controls connecting the stand-by generating units (either shutdown or used as synchronous capacitors) to the group control system when the power system frequency falls to 48.8-49.7 Hz or when the station lacks generation to properly cover the specified load schedule. When the frequency falls to 49.5 Hz the setter of the group control device must automatically change to a setting which ensures the maximum generation of real power.

9. The real power group control devices and the load schedules for large-rated thermal stations not enveloped by a group control system, make it possible to run the power system without frequent interference by the attending personnel to the operation of individual power plants and generating units. Economic and reliable operation of a power system is dependent on a well designed foresight load schedule. Unscheduled variations in the load (against the daily load schedule) should not exceed 3 per cent of the planned load.

10. Unscheduled loads manifest themselves by a change in frequency from the rated (preassigned) value. Unscheduled load variations and reestablishment of the frequency is placed with a small number of frequency-regulating power stations which must possess a required flexible power reserve. For this the most suitable are hydroelectric power stations, then water storage and gas-turbine power stations. Less suitable for the purpose are the powerful generating units of thermal stations as load changes have to be combined with the operation of the automatic heat control devices which generally results in uneconomical operation.

11. If only one frequency-regulating hydroelectric power station deals with the removal of an unscheduled load burden one frequency regulator at the station is sufficient. The "increase" or "decrease" effect of the frequency regulator on the group control system must be corrected to the value of real power flows over the lines connecting the power station with the power system and stopped by the flow limiters installed on the tie lines.

12. When several regulating power stations are used, to remove an unscheduled load from the power system, they may be operated by a group control system from the load-dispatching department of the power system. The real power value which corresponds to the share of the respective power plant to cover the unscheduled load is assigned at the system.

Each power station assignment is corrected by a frequency corrector which stops the transfer of control pulses when the frequency decreases or increases

beyond ± 0.2 Hz from the rating or it also creates a steady-state stability $P = \varphi' (f)$ for executing the assignment within the range.

13. The amalgamation of individual power systems into one integrated large power grid makes it necessary to use several power plants in various areas to handle unscheduled loads and to prevent overloading of the tie links to a value dangerous to the steady-state stability.

These tasks can be fulfilled by the central frequency, power and power flow regulator which operates in conjunction with the flow limiters on the overloaded tie links. The input of the variables under control to the regulator from remote plants and the output of control pulses are carried out by the remote control devices.

The effect of the power flow limiters on the central regulator should be backed up by the local power flow limiters which determine the critical value of real power transmission from system to system (the power "balance" on the tie links) and effect the unloading of the power plants in the given power system to limit the power flows. The unloading of power plants electrically close to the overloaded tie line is most effective.

Special attention should be paid to organizing an automatic power flow limiting system in order to completely utilize the transmission capacity of the tie links between the power systems and power plants of the integrated grid. This system must be installed in the first place, even if it is used in the future as a stand-by one.

14. It is necessary and in principle possible to use an electronic computer as a central frequency, output and power flow regulator to take into account the diversity of the factors encountered in the current service of the power system and determine the efficiency and reliability of the grid system operation. Researches on these lines are now conducted by a number of scientific organizations. At first it is planned to use the computer as an "adviser" to the dispatcher and then as a machine to control the operation of the integrated power systems.

6-9. Review Questions

1. What is the significance of the automatic control of frequency and real power for operation of a power system? Name the advantages of automatic control over manual control.
2. What are the permitted frequency deviations specified in GOST Standards as to the quality of power supply?
3. What are the measures taken by the load-dispatching personnel to maintain the frequency within the permissible limits?
4. Is automatic frequency control possible in a system having no real power spinning reserve?
5. Substantiate the expediency of automatic reconnection of shutdown hydroelectric generators when the power system frequency falls.
6. What is the purpose of the turbine speed governors? When the electrical load on a generator increases does the primary speed governor increase or decrease the fuel (water) supply to the turbine?
7. What are the regulating characteristics $n = \varphi (P)$ ensured by the primary speed governors? What is the steady-state coefficient of these characteristics and its effect on the allocation of load among paralleled generating units?

8. What is the purpose of the turbine limiters as to the upper and lower limits of control? What is the position of the limiters during proper operation of the speed governors and the automatic heat control devices?

9. What is the purpose of the automatic safety device of a turbine? What are the critical speed limits of high-speed turbogenerators and low-speed hydroelectric generators?

10. What are the secondary regulators of frequency and power? Describe the methods used in the group control of the generating units employed in multi-unit thermal and hydroelectric stations.

11. How is the economy of operation of individual generating units considered when group control of the real power generation of a thermal station is accomplished?

12. What is the allocation of load among the generating units by the method of relative incremental reference fuel consumption (labour costs)? What is the possibility for automatic preparation of assignments for individual generating units and power plants?

13. When must corrections or limitations to the power flow over outgoing tie lines in the real power regulation law by the generators of a given power station be introduced?

14. To cover the real power deficit in the power system all generators everywhere initially take part in accordance with the steady-state characteristic of the primary speed governors. How should one ensure that the real power deficit is met by the generating units of the power plant assigned for frequency regulation?

15. What are the causes of regular swings in power flows between power stations and power systems operating in parallel? Should the power flow regulation system and the power flow limiting system suppress these regular swings?

16. What are the principles underlying the automatic limitation system of real power flows between the terminal power system and the central system, between intermediate power systems, and between power systems combined into a ring grid?

17. How is it that the frequency stability increases with an increase in the generation output of an integrated power system and why are a limited number of power stations whose generating units are under the effect of the frequency regulator sufficient to hold the frequency constant? Name the variants of regulating the frequency, real power and power flows (AFP&FC) in the integrated power systems.

18. What automatic controls make it possible for a power station to operate against a preassigned real-load schedule? What are the specific features of group control at hydroelectric and thermal power plants when these plants are intended for handling unscheduled loads of a power system?

19. What are the requirements for a combined AFP&FC system in an integrated power system? What are the functions of the central regulator? Is it possible to use a high-speed computer as the computing device of the central regulator? What is the purpose of the power flow limiters acting on the generators of local power plants of individual power systems?

20. Describe the principal advantages of automatic control of frequency and real power used in integrated power systems over manual control? How do operators participate in the automatic control of frequency, real power and power flows over the intersystem links?

21. A tie link of two parallel lines connects two power systems A and B. The flow of real power is from the power system A to the power system B. Owing to disconnection of some loads of the system A at the hours of minimum demand, the power flow over the tie lines to the power system B rises and approximates the steady-state stability limit. What actions must be performed by the power flow limiters at the power plants of the systems A and B when the pickup setting is reached?

22. In the case above, the power flow regulator is inoperative. What steps should the attending personnel of the power system take?

Chapter Seven

RAPID PARALLELING OF SYNCHRONOUS GENERATORS AND PARTS OF POWER SYSTEM

7-1. General

To prevent or eliminate faults, the rapid connection of stand-by generators and the reestablishment of synchronous operation of those parts of the power system which had been sectionalized due to asynchronous operation are very important. In this connection special researches were undertaken to find methods which would enable synchronous machines and parts of the power system to be quickly, automatically or manually, brought into parallel operation when the power system operates on abnormal frequency and voltage.

When the power station and the power system operate under normal operating conditions, parallel connection of synchronous generators and compensators having starting motors is to be performed as a rule by the precise synchronizing methods[7-1]. In particular this applies to the turbogenerators with indirect cooling of the windings working into the generator voltage busbars and also to generators with directly-cooled windings and synchronous machines with winding reception slots on the rotor.

Accurate synchronization is effected when the following conditions are satisfied:

The speed of the excited generator is regulated so that the frequency of the generator equals that of the circuit, the slip of the rotor of the generator being connected should lie within 0.3 to 0.4 per cent.

The excitation of the machine should be set so that the voltage of the incoming generator is exactly the same as the line to which it is to be connected.

The incoming generator is connected to the line at the instant when the vectors of the same phases of voltage and circuit coincide.

When the above conditions are satisfied the generator is connected without current surges and short-time voltage dips, i.e., without arising of equalizing currents and occurance of heavy swings. However, paralleling a generator by the precise synchronizing method requires much time and attention on the part of the operators. The operators' work is especially difficult, when placing the parts of a power system into parallel operation under emergency conditions as in the case of a load frequency fall. The ACT-4 type synchronizer[7-2] described below makes the work of the operating personnel much easier, as proper operation of the synchronizer is ensured both at the normal values of frequency and voltage and when the frequency falls to 45 Hz and the amplitudes of the voltages being synchronized vary within ± 15 per cent of the rating. The great

advantage of the ACT-4 synchronizer is that it uses no vacuum tubes and is ready for operation at all times.

Among the methods which make it possible to quickly connect synchronous machines for parallel operation either manually or automatically, not only under normal operating conditions, but also in case of emergency are the self-synchronizing method and asynchronous method for connection of a group of excited generators.

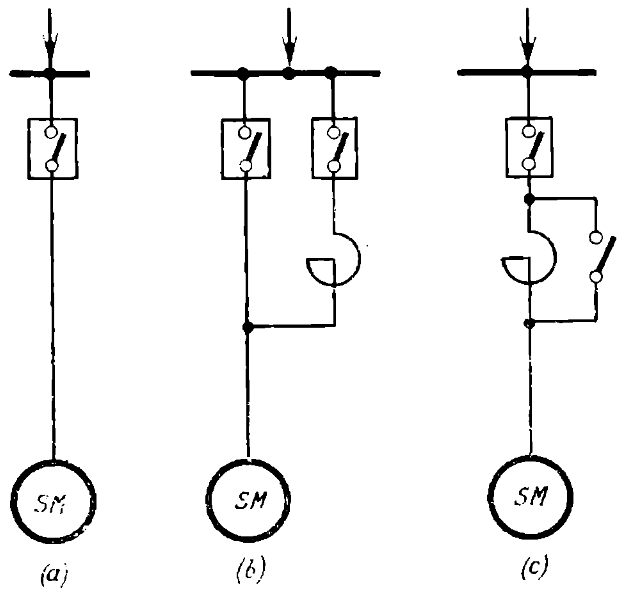


Fig. 7-1. Connection of synchronous motors across the line
(a) direct start; (b, c) reactor start

As stated in reference [7-1] the self-synchronizing method may be used for emergency connection of generators and synchronous compensators regardless of their type, construction, cooling system, rating and wiring diagrams. The use of asynchronous connection calls for a preliminary assessment of its suitability (see below).

As regards the paralleling of synchronous motors, they are usually started by the so-called across the line (direct start) method (Fig. 7-1) in which the line voltage is directly applied to the stator winding. The rotor starts rotating under the action of an asynchronous torque. When a hyposynchronous speed is reached the motor is pulled in synchronism, as with an increase in the rotor speed the current in the rotor winding and the torque rise to the input value (which takes place when the winding is constantly connected to an exciter) or after an abrupt increasing of the rotor winding current produced by the starting automatic devices [7-3], [7-4].

Large synchronous motors and compensators are usually started via starting reactors reducing the starting current. As the speed rises, the current value reduces. When the motor reaches a speed close to the hyposynchronous value, the automatic starting devices actuate the switches bypassing the starting reactor (the switch in Fig. 7-1*b* and the power disconnector in Fig. 7-1*a*) in order to increase the terminal voltage of the synchronous motor to the nominal value and raise correspondingly the starting torque to achieve synchronism.

This Chapter deals with the methods for rapid connection of synchronous generators, motors and parts of a power system applied in the scope of automatic control systems.

7-2. Precise Synchronization by Means of an ACT-4 Autosynchronizer

The type ACT-4 synchronizer gives a connecting pulse during the interval when the emf vectors of the incoming machine and the line voltage approach each other, i.e., when the angle δ changes from 270 to 360 degrees. The control

signal sending point is selected so that the time of switch closure is taken into account, i.e., that the contacts of the switch are made at an angle δ close to 360 degrees. In this case the excessive shaft torque of the machine is small and the generator achieves synchronism at once without hunting and without asynchronous running.

If the time from the instant the signal is sent to close the switch is constant and equals t_{cls} the synchronizer must produce the control pulse $t_{lead} = t_{cls}$ before the angle δ reaches 360 degrees, i.e., the control pulse is leading.

The leading time is constantly independent of the slip frequency. With the type ACT-4 synchronizer the leading time variations do not exceed 3 electrical degrees at frequency differences ranging from $f_s = 0.25$ Hz to $f_s = 0.04$ Hz.

The essential elements of the ACT-4 synchronizer (Fig. 7-2) are a differentiating transformer, a lead relay, a frequency difference control relay, a

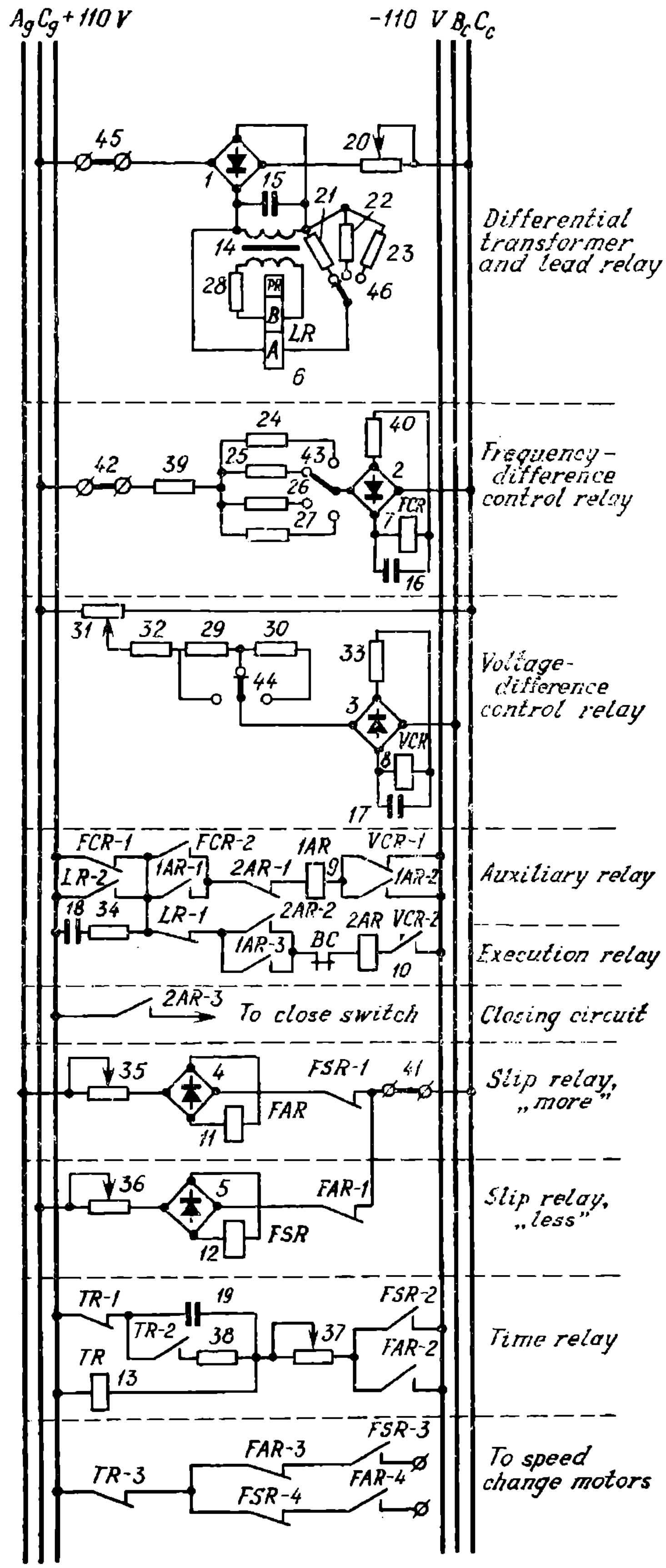


Fig. 7-2. Internal connection of type ACT-4 autosynchronizer

1 through *5* — rectifiers; *6* — lead relay (*LR* — polarized relay); *7* — frequency control relay (*FCR* — polarized relay); 8 — voltage control relay (*VCR* — polarized relay); *9* — auxiliary relay *1AR*; *10* — auxiliary relay *2AR*; *11* and *12* — slip relays (*FSR* and *FAR* are auxiliary relays); *13* — time relay (*TR* — auxiliary relay); *14* — intervening transformer; *15* through *19* — capacitors; 20 through *40* — resistors; *41* through *46* — bridges and switches; *BC* — block-contacts of switch

voltage difference control relay and a device for frequency alignment. The differentiating transformer and the lead relay are the elements which create the constant lead time of the control signal with regard to the optimum point, i.e., the instant when $\delta = 360$ degrees.

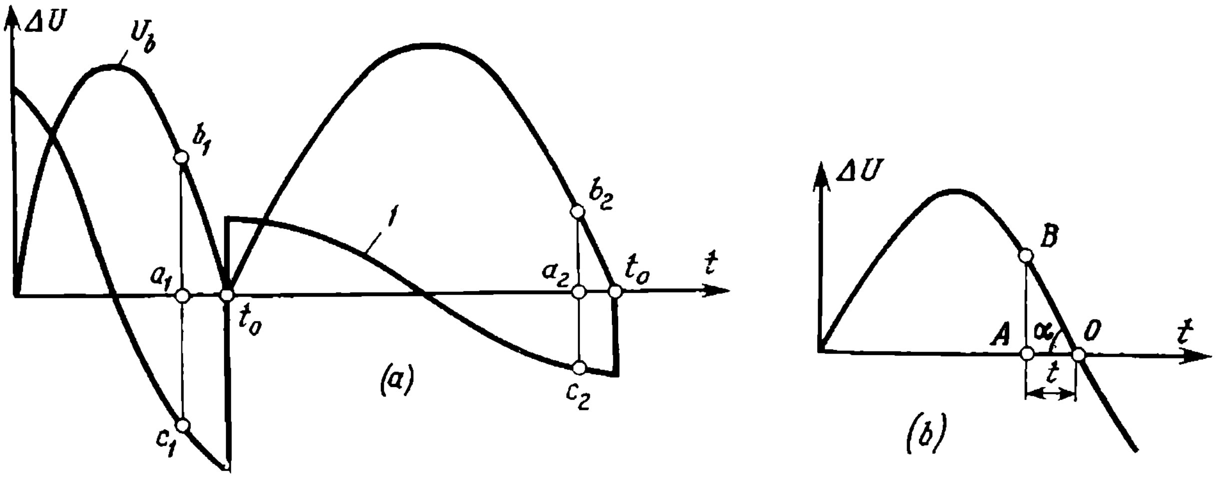


Fig. 7-3. Diagram explaining operation of lead relay
1 — voltage across secondary winding of differentiating transformer

The primary winding of transformer *14* having a core with an air gap is connected to the beat voltage. First, the voltage is rectified by rectifier *1* and smoothed down by capacitor *15*.

During each beat cycle the rectified voltage continuously changes its value. As a result, an emf is induced in the secondary winding of the transformer. The secondary voltage changes its polarity at the maximum of the primary voltage and, when the phase vectors of the generator and circuit emf coincide reaches its maximum amplitude (Fig. 7-3*a*).

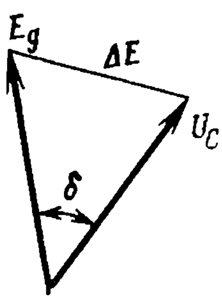


Fig. 7-4. Explanatory diagram

If the generator emf E_g equals the circuit voltage U_c then, in compliance with the diagram in Fig. 7-4, the voltage applied to the primary winding of the transformer

$$\Delta U = 2U_c \sin\frac{\delta}{2} = 2U_c \sin\frac{\omega_s t}{2} = 2U_c \sin\left(\frac{2\pi f_s t}{2}\right) \qquad (7\text{-}1)$$

where ω_s and f_s are the angular velocity and beat frequency with slip s.

The current flow in coil A of the polarized relay LR (Fig. 7-2) is proportional to this voltage

$$i_{1\,LR} = k_1 \Delta U \qquad (7\text{-}2)$$

Coil B of the relay LR is connected to the secondary winding of the differentiating transformer and carries a current

$$i_{2\,LR} = -k_2 \frac{\partial(\Delta U)}{\partial t} \qquad (7\text{-}3)$$

In expressions (7-2) and (7-3) k_1 and k_2 are proportionality factors whose values are controlled by adjusting resistors *20*, *21* to *23* and *28*.

In compliance with (7-1) the currents are

$$i_{1\,LR}=k_1 2U_c \sin\left(\frac{\omega_s t}{2}\right) \tag{7-4}$$

and

$$i_{2\,LR}=-k_2 2U_c \frac{\omega_s}{2} \cos\left(\frac{\omega_s t}{2}\right) \tag{7-5}$$

The polarized relay LR is connected so that when the current flows in coils A and B are equal

$$i_{1\,LR}=i_{2\,LR} \tag{7-6}$$

the relay contacts drop out.

As seen from (7-4) and (7-5), conditions (7-6) takes place when

$$k_1 2U_c \sin\left(\frac{\omega_s t}{2}\right)=-k_2 2U_c \frac{\omega_s}{2} \cos\left(\frac{\omega_s t}{2}\right)$$

i.e.

$$\tan\left(\frac{\omega_s t}{2}\right)=-\frac{k_2}{k_1}\frac{\omega_s}{2} \tag{7-7}$$

With angles δ being small

$$\tan\left(\frac{\omega_s t}{2}\right)\approx\frac{\omega_s t}{2} \tag{7-8}$$

hence

$$\frac{\omega_s t}{2}=-\frac{k_2}{k_1}\frac{\omega_s}{2} \tag{7-9}$$

thus

$$t=-\frac{k_2}{k_1}=-k_3=\text{const} \tag{7-10}$$

regardless of the slip magnitude.

The contacts of relay LR are dropped out before the angle reaches 360 degrees, i.e., the drop-out takes place at a negative angle δ.

It is seen from the diagram in Fig. 7-3, that the equality of sections a_1b_1 and a_1c_1 or respectively a_2b_2 and a_2c_2 occurs when the values a_1t_0 and a_2t_0 equal each other, i.e., the rigorously specified time to lead the optimum point is always observed. The lead time is repeated each beat cycle regardless of the difference between the frequencies and values of the voltages being synchronized.

The possibility of determining the lead time t_{lead} from the condition of equality between the currents $i_{1LR}=k_1U_b$ and $i_{2LR}=k_2\,\partial U_b/\partial t$ (where U_b = beat voltage) can be also shown like this (V.L. Fabrikant). Let a length of straight line substitute for the beat sine curve $U_b=f\,(t)$ near the zero value point (Fig. 7-3*b*) [the approximate assumption corresponds to assumption (7-8)].

From the triangle OAB, $t = U_b/\tan\alpha$, hence $t = \frac{U_b}{\partial U_b/\partial t}$ which determines the connection circuit of the coils of relay *LR*.

The difference between the frequencies of the voltages being synchronized is controlled by the *FCR* relay connected via rectifier *2* to the beat voltage. The relay functions when its terminal voltage becomes equal to or less than the drop-out voltage. For each setting the drop-out voltage is determined from the expression

$$U_{d\text{-}o} = 2U_c \sin\frac{2\pi f_{s\,p} t_{lead}}{2} \tag{7-11}$$

where U_c = value of the voltages being synchronized
$f_{s\,p}$ = permissible specified difference of the frequencies of the voltages being synchronized
t_{lead} = time to lead the optimum point which is equal to the own closure time of the switch

The frequency at which the *FCR* relay drops out its armature (control of the drop-out frequency) is controlled by changing the values of resistors *39* and *24* to *27*.

The capacitance of capacitor *16* and the value of resistor *40* connected in parallel with the coil of relay *7* are selected so that the decrease of the magnetic

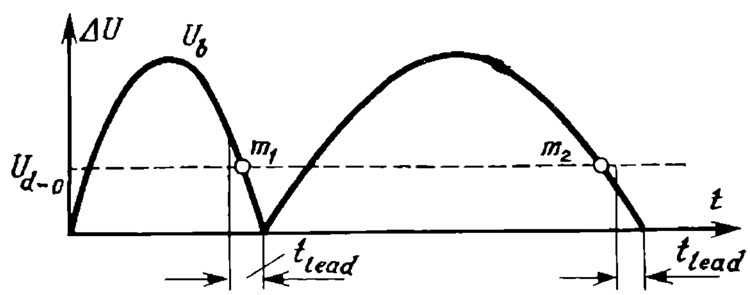


Fig. 7-5. Diagram explaining joint operation of lead and frequency contro relays

t_{lead} — optimum lead time; m — moment when frequency control relay picks up

flux in the magnetic circuit of relay *7* to a value at which the relay armature drops out under the action of its spring takes place at a beat frequency $f_s \leqslant$ $\leqslant$ (0.2 to 0.3) Hz.

The drop-out voltage $U_{d\text{-}o}$ determined by (7-11) is dictated by the condition of the joint operation of the frequency control relay and the lead relay. If the slip frequency is greater than the specified frequency $f_{s\,p}$ then, as seen from Fig. 7-5, it is the lead relay that drops out first leading the optimum point by the time t_{lead}. The frequency control relay having a drop-out setting selected by (7-11) is the second to drop out (at point m_1). The connection circuit of the lead relay *LR* and the frequency control relay *FCR* is so designed that the switch cannot be closed in this case. If the slip frequency is less than the speci-

fied value $f_{s\,p}$, the frequency control relay drops out first (at point m_2) and then the lead relay does. In this case the switch closes.

Control of coincidence of the voltages being synchronized is performed by the relay *VR* (see Fig. 7-2). The beat voltage of phases C_c and C_g is applied to potentiometer *31*. From the midpoint of the potentiometer and phase *B* common to the secondary circuits of the instrument voltage transformers, installed from the

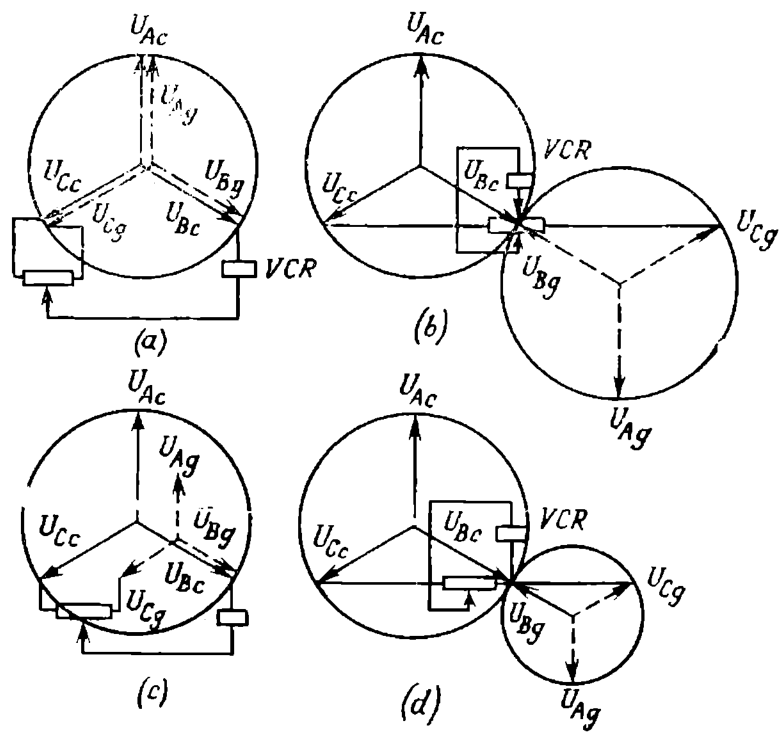


Fig. 7-6. Diagram explaining operation of relay used to control coincidence of voltages being synchronized

(a) $U_c = U_g$, $\delta = 0$; (b) $U_c = U_g$, $\delta = 180°$; (c) $U_c > U_g$, $\delta = 0$; d — $U_c > U_g$, $\delta = 180°$

line and generator side, the beat voltage is applied via resistors *29*, *30* and *32* to the coil of d. c. relay *8* connected through rectifier *3*. Capacitor *17* is connected in parallel with the coil of relay *8* and resistor *33*, in series with it. Capacitance *17* and resistance *33* are selected so that relay *8* drops out its armature at a beat frequency $f_s < (0.2\text{-}0.3)$ Hz. The value of the armature drop-out current of the relay can be controlled by switch *44*.

Shown in Fig. 7-6 are diagrams explaining the ooeration of the relay controlling the coincidence of the voltages being synchronized. If the voltage U_c is equal in value and phase to the voltage of the incoming generator U_g, then, as seen from Fig. 7-6*a*, the coil of relay *VCR* will have the voltage

$$U_{p\ VCR} = k\sqrt{3}\,U_{ph} \tag{7-12}$$

where k = proportionality factor

U_{ph} = phase voltage

When the vectors $\dot{U}_c$ and $\dot{U}_g$ are 180 degrees apart, the voltage to the *VCR* relay is zero (Fig. 7-6*b*).

The relay functions upon drop-out of the armature, i. e., operation of the relay takes place when the angle δ rises to 180 degrees.

If the voltages do not equal each other ($U_c > U_g$), then, when the vectors of the voltages being synchronized coinci de, they correspond to Fig. 7-6*c* and *d*

$$U_{p\ VCR} = k\left[\frac{\sqrt{3}}{2}(U_{ph.\ c} - U_{ph.\ g}) + \sqrt{3}\,U_{ph.\ g}\right]$$

or

$$U_{p\ VCR} = k\,\frac{\sqrt{3}}{2}\,(U_{ph.\ c} + U_{ph.\ g}) \qquad (7\text{-}13)$$

When the angle δ reaches 180 degrees, the coil of the *VCR* relay will have the voltage

$$U_{p\ VCR} = k\,\frac{\sqrt{3}}{2}\,(U_{ph.\ c} - U_{ph.\ g}) \qquad (7\text{-}14)$$

The voltage applied to the *VCR* relay when angle δ = 180 degrees is determined by the difference between the voltages being synchronized

$$\Delta U = U_{ph.\ c} - U_{ph.\ g} \qquad (7\text{-}15)$$

The relay *VCR* drops out the armature each beat cycle within the region of angles close to 180 degrees. The armature is reattracted when ΔU increases, i. e., when the angle δ approaches 360 degrees. The value of angle δ at which the armature is attracted is a function of the reset coefficient of the relay.

The relay shown in Fig. 7-2 operates as follows. If the difference between the voltages being synchronized does not exceed the specified value, then, when the voltage vectors are at an angle close to 180 degrees, the contacts of the voltage difference control relay *VCR* close (the *VCR-1* contact is closed). At the same time (during the first half the beats) the lead relay *LR* and the frequency control relay *FCR* function.

The coil of relay *1AR* is made by contacts *LR-2* and *FCR-2*. The relay *1AR* functions and interlocks itself by contacts *1AR-1* and *1AR-2*. Simultaneously the contact *1AR-3* of relay *1AR* prepares the circuit for operation of the output relay *2AR*. The relay *2AR* functions after the relay *VCR* has attracted the armature and closed the contacts *VCR-2*, the contacts *LR-1* and *FCR-1* being closed at that time.

The control relay *2AR* must operate only when the frequency-control relay *FCR* drops out its contact before it is dropped out by the lead relay *LR* (Fig. 7-5).

This operation in the circuit shown in Fig. 7-2 is obtained due to the fact that the relay *1AR* is held in a closed position only in the case when the *FCR-1* contact of the lead relay closes before the *LR-2* contact of the lead relay opens.

Deenergizing the relay *1AR* results in breaking the circuit of the relay *2AR* and thus prevents the switch from being closed.

The circuit provides bypassing of the contact *1AR-3* by the contact *2AR-2*. This is done to ensure self-holding of the relay *2AR* through the contact *FCR-1* after operation of the relay *2AR*. Capacitor *18* and resistor *34* are used to facilitate operation of the contacts. The circuit of the relay *2AR* is controlled by

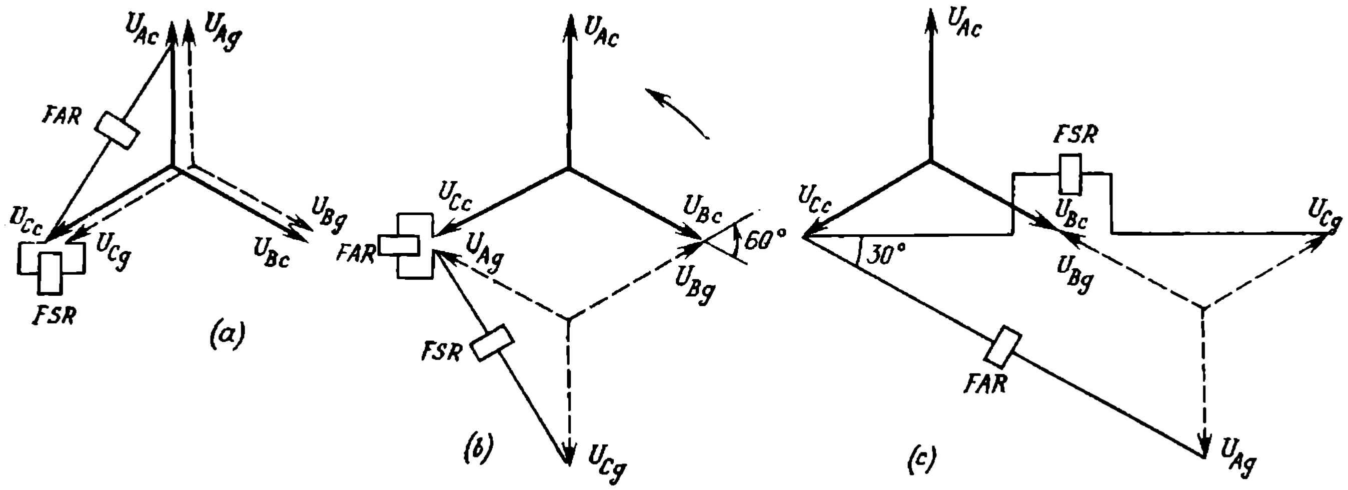


Fig. 7-7. Voltage across coils of relays *FSR* and *FAR* (see Fig. 7-2)
(*a*) when vectors U_{Ac} and U_{Ag} coincide; (*b*) when vector U_{Ag} leads vector U_{Ac} by 60 degrees; (c) same by 180 degrees

the blocking contact *BC* of the switch which is closed when the switch is opened.

The frequency alignment device includes two slip relays *FSR* and *FAR* and one time relay.

The operating principle of the device is as follows[7-5]: the relay *FAR* is connected via rectifier *4* and adjustment resistor *35* to the voltage $U_{FAR} = U_{Ag} - U_{Cc}$ (A_{Ag} is the phase *A* voltage from the generator side; U_{Cc} is the phase *C* voltage from the circuit side).

The relay *FSR* is connected through rectifier *5* and adjustment resistor *36* to the voltage $U_{FSR} = U_{Cg} - U_{Cc}$ (U_{Cg} is the phase *C* voltage from the generator side).

The voltage is supplied to the coils of relays *FAR* and *FSR* from the instrument voltage transformers of the circuit and the generator. The secondary circuits of phase *B* of the instrument transformers are interconnected.

When the vectors $\dot{U}_{Ag}$ and $\dot{U}_{Ac}$ are in phase, the voltage on the coil of relay *FSR* is zero (Fig. 7-7). The voltage is at its maximum when the vectors $\dot{U}_{Ag}$ and $\dot{U}_{Ac}$ are 180 degrees apart. Depending on the angle δ the voltage ΔU_{FSR} is determined by curve *2* in Fig. 7-8 whose equation is

$$\Delta U_{FSR} = 2U_{i\,ph} \sin \frac{\delta}{2} \tag{7-16}$$

No voltage will be applied to the coil of relay *FAR* if the vector $\dot{U}_{Ag}$ leads the vector $\dot{U}_{Ac}$ by 60 degrees.

Depending on the angle δ the voltage ΔU_{FAR} is determined by the sine curve whose equation is

$$\Delta U_{FAR} = 2U_{i\,ph} \sin\left(\frac{\delta + 60^\circ}{2}\right) \qquad (7\text{-}17)$$

The voltages applied to the relays *FAR* and *FSR* versus the angle δ are shown in Fig. 7-8.

The angle δ is positive when the speed of the incoming generator is greater than the speed of the generators of the power system.

The pickup settings of the relays *FSR* and *FAR* are the same.

If the speed of the incoming generator is *less than* the speed of the power system generators the relay *FAR* operates *first* in each beat cycle. In this case the contact *FAR-1* breaks the circuit of relay *FSR* and a control pulse "more" is sent by the contact *FAR-4* over the circuit *FAR-4* — *FSR-4*.

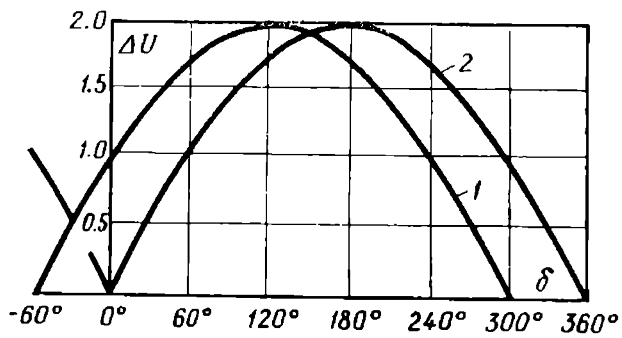


Fig. 7-8. Voltage across coils of relays *FAR* (*1*) and *FSR* (*2*) connected as in Fig. 7-7 depending on the angle δ between the vectors of voltages being synchronized

If the speed of the incoming generator is *greater than* that of the power system generators, the relay *FSR* will *operate first*, thus opening the contact *FSR-1* and closing the contact *FSR-3*. In this instance the relay *FAR* is rendered ineffective and its contact *FAR-3* remains closed. A control pulse "less" is fed to the speed control mechanism via the circuit *FAR-3* — *FSR-3*.

The time relay in the circuit shown in Fig. 7-2 limits the duration of control pulse to a certain critical value. This time is set to 0.2-0.3 s, which promotes equal duration of action practically independent of the slip frequency of the incoming generator with respect to the power system generators. Limitation of the control pulse duration is obtained because the starting circuit of the motor actuating the turbine speed control mechanism is triggered via contacts *TR-3*.

The coil of auxiliary relay *TR* becomes energized when the *FSR-2* or *FAR-2* contacts close. However, at the first instant of closure the coil of relay *TR* is bypassed by capacitor *19*. After the capacitor *19* is charged the relay *TR* functions. The charging time of the capacitor determines the pickup time of relay *TR*.

When functioning, the relay *TR* breaks the circuit of capacitor *19* with its contact *TR-1* and connects this capacitor to resistor *38* with its contact *TR-2* to discharge the capacitor and make the relay ready for the next operation. The relay *TR* remains closed until the relay contacts *FSR-2* or *FAR-2* are closed, i. e., the relay *TR* functions every beat cycle.

Resistor *37* is used to control the voltage across the coils of relay *TR* and capacitor *19* in order to promote the control of the time delay of relay *TR* and the duration of the control pulse fed to the motor actuating the speed control mechanism of the turbine.

7-3. Self-Synchronization of Generators

Paralleling the generators by the self-synchronizing method is as follows: While yet unexcited, the machine is run up close to the synchronous speed. When the slip (s) is within ± 3 per cent, the stator winding becomes energized. Next, the AFD device turns on the excitation.

Under emergency conditions the above-mentioned amount of slip may be somewhat exceeded. In practice, cases have been noted, when self-synchronization was used to parallel turbogenerators having a slip of $+20$ per cent and

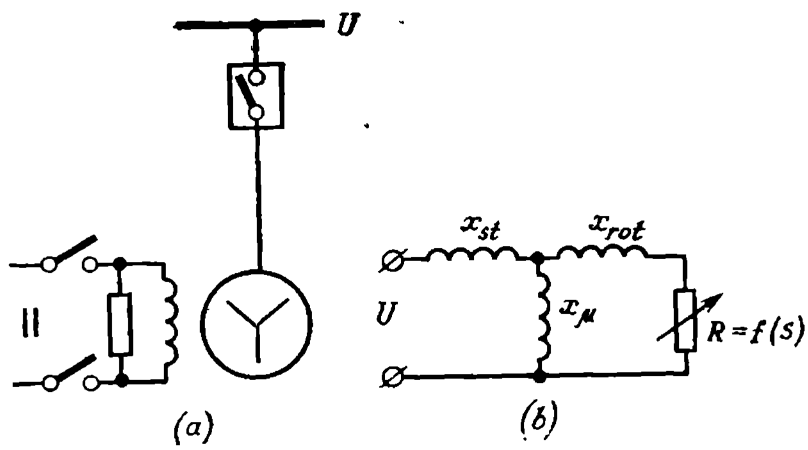


Fig. 7-9. Connection of unexcited synchronous generator
(*a*) connection diagram; (*b*) equivalent circuit diagram

hydroelectric generators with damping coils having a slip of ± 15 per cent. The slip is positive, if the speed of the incoming generator is *less than* the the speed of the power system generators.

The slip values at which the stator winding is connected to the power system voltage are usually dependent on the acceleration of the incoming machine. The higher the acceleration, the greater the positive slip at which the connection may be performed. When connecting the generators by the self-synchronizing method, the time taken by the transient processes does not exceed 2 s.

The equivalent circuit of a synchronous generator with a rotor connected to a damping resistor is similar to the equivalent circuit of a power transformer, the primary winding of which is connected to the voltage, while the secondary winding is connected to resistor R (Fig. 7-9).

At the first moment the equivalent inductive reactance of the machine is at its least value and is determined by the value of supertransient reactance x''_d (the reactance x_μ of the magnetizing leg is small). With time the free cur-

rents decrease with resulting reduction in their demagnetizing effect. The reactance x_μ of the equivalent circuit increases. The equivalent inductive reactance of the generator rises.

After the free current in the damping coil of the rotor has decayed, the equivalent inductive reactance of the machine is roughly assessed by the quadrature-axis transient reactance x'_d.

The free current in the stator winding, an aperiodic current caused by it in the rotor loops, and the free current in the damping coil decay within 0.04 to 0.06 s, so that the greatest *operating* value of the stator current, when connecting an *unexcited* generator to the line voltage U_c may be determined by the expression

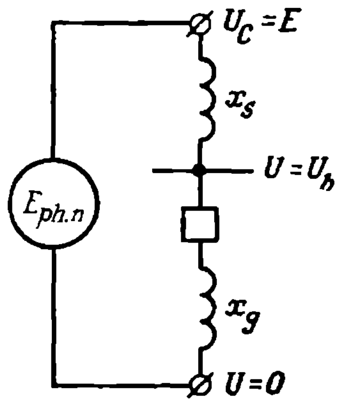


Fig. 7-10. Calculating circuit

$$I'_{con.\,s}=\frac{U_c}{x'_d+x_s} \tag{7.18}$$

where x_s is the system reactance.

Whether a generator is permitted to be connected by the self-synchronizing method depends on the value of $I'_{con.s}$ calculated with the aid of (7-18). If this value does not exceed the 3.5-fold value of the generator rated current, no limitations are laid down on the use of the self-synchronizing method for connecting the machine to the power system under emergency conditions. It is taken into account, that with a chort circuit at the terminals of an excited generator the current flowing in the stator winding is

$$I_{s.\,c}=\frac{U_c}{x_g} \tag{7.19}$$

where x_g is the design inductive reactance of the generator for the given time, i.e., $I'_{s.c}$ is always greater than $I'_{con.s}$ and the generators are so built that they must withstand short circuits at the terminals and in the external circuit.

Connecting the generators by the self-synchronizing method always entails a decrease in the voltage across the terminals and in the line connecting the incoming generator to the power system.

The terminal voltage of a generator being synchronized (the busbar voltage U_b in Fig. 7-10) can be determined as follows

$$U_b=U_c-I_gx_s \tag{7-20}$$

On the other hand, like in (7-18) for each point of time

$$I_g=\frac{U_c}{x_g+x_s} \tag{7-21}$$

where x_g is the design inductive reactance of the generator.

It follows from (7-20) and (7-21) that

$$U_b=U_c\left(1-\frac{x_s}{x_g+x_s}\right) \tag{7-22}$$

If at the first moment $x_g = x_s$, the voltage across the busbars will fall to 50 per cent of the rated value. As the generator is pulled into synchronism the voltage is reestablished on the one hand due to an increase in the generator reactance (for example, x_d is about $3x_d'$ for hydroelectric generators) and on the other, due to the operation of the forcing devices and excitation regulators.

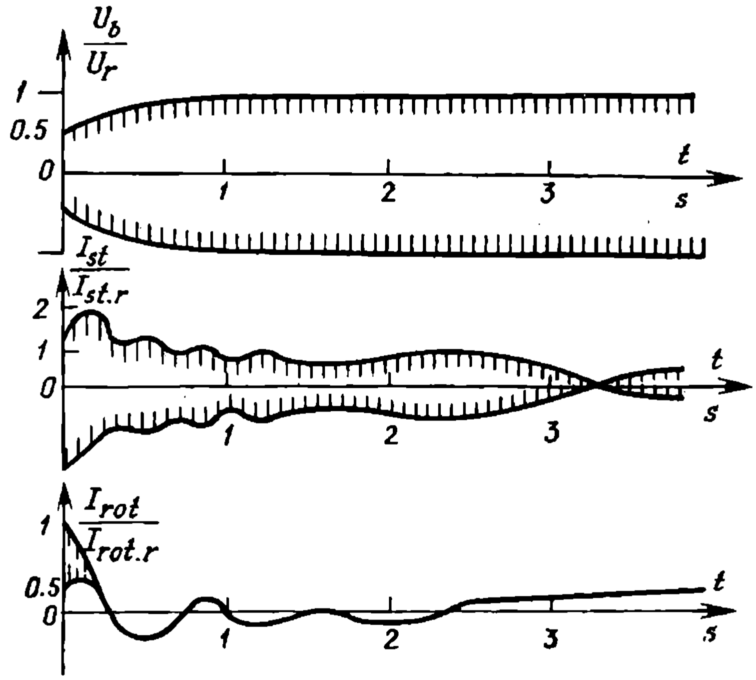


Fig. 7-11. Oscillogram of process of connecting a turbogenerator to another one equal in rating by the self-synchronization method when slip $s = 1\%$

Shown in Fig. 7-11 are characteristic oscillograms illustrating the self-synchronization process, namely changes in the terminal voltage of the generator stator, stator current and rotor current in time. The connection is performed at a slip s = 1 per cent[7-6].

It is seen from the oscillogram that the voltage abruptly dropped to about 50 per cent of the rated value at the instant of connection. As the starting current decays, the voltage recovers and reaches the rated value in 0.8 s.

The pulling of the generator into synchronism after excitation has been applied is determined by the resultant effect of the following torques [7-7]:

(a) The excess torque T_{ex} equal to the difference between the torque T_t developed by the turbine with the given speed and the resisting torque T_r determined by the generator load. The excess torque accelerates the generating unit. Under the effect of the turbine speed governor, the excess torque goes to zero when the generator speed becomes close to the rated value.

(b) The synchronizing torque T_s developed by the generator due to the interaction of the rotor field, produced by the field current and the stator

field. Its value is given by

$$T_s = \frac{E_{d\,st} U_b}{x_d} \sin \delta \qquad (7\text{-}23)$$

where $E_{d\,st}$ = generator emf at a steady rotor current

δ = angle between the vector $\dot{E}_{d\,st}$ and the voltage vector $\dot{U}_b$

(c) The reactionary torque T_{reac} developed by the rotor due to the interaction between the rotating stator field and the salient poles of the rotor. The maximum value of the reactionary torque is determined by the amount of load that can be carried by the unexcited generator operating in step with the power system.

The reactionary torque is proportional to the square of the stator terminal voltage and varies in time with a doubled slip frequency

$$T_{reac} = U_b^2 \frac{x_d - x_q}{2x_d x_q} \sin 2\delta \qquad (7\text{-}24)$$

where x_d and x_q are the generator direct-axis and quadrature-axis synchronous inductive reactances.

At the presence of a synchronizing torque, the generator pulling-in process is influenced by the reactionary torque, but not perceptibly, since the mean value of reactionary torque is equal to zero while the angle δ varies from 0 to 180 degrees. At the absence of the synchronizing torque, the generator may pull in synchronism under the action of the reactionary torque both when the voltage vectors of the generator and the line are coincident and when they are 180 degrees apart.

In order to avoid pulling the generator in synchronism, when the voltage vectors of the generators and the line are 180 degrees apart, the excitation is applied (under the self-synchronizing conditions) till the generator has pulled in step, i.e., at a certain positive slip.

(d) Mean asynchronous torque $T_{m.as}$ developed by the generator when the rotor slips. Like the torque of an asynchronous motor, the mean asynchronous torque of a generator is produced by the interaction between the revolving magnetic flux of the stator and the currents induced in the closed loops and circuits of the rotor (field winding, damper winding and rotor core).

The mean asynchronous torque of a generator is proportional to the square of voltage across the terminals of the stator winding and depends on the magnitude of slip. When the slip equals zero, the asynchronous torque is also equal to zero. When the slip increases, the torque rises too and reaches its maximum when $s = s_{cr}$ (Fig. 7-12).

When hydroelectric generators are furnished with damper windings, the characteristic of asynchronous torque is somewhat different from that of hydroelectric generators without damper winding, namely, the maximum values of the asynchronous torque are shifted towards greater slips.

The action of asynchronous torque always adds to pulling the generator in synchronism.

A generator is pulled in synchronism as follows. When the generator runs at a speed below the synchronous one, an asynchronous torque arises after the stator winding has been connected to the line voltage. This torque adds to the generator speed and thus makes the slip smaller*. When the slip becomes comparatively small, the excitation is applied to the generator and a synchronous torque arises which pulls the generator in synchronism after several swings. In this case the influence of the reactionary torque is insignificant.

The synchronizing process is considerably affected by the adjustment of the speed governor. With hydroelectric generators having no damper windings, the best conditions for self-synchronization occur when the gate apparatus is constantly open. In this case the slip must be positive at the instant the connection to the circuit is performed and the excess torque at an hyposynchronous speed must be within 0.15-0.2 of the T_{rated}.

The use of excitation forcing and automatic regulation devices reduces the time taken by the voltage recovery in the process of self-synchronization. However, if the generator stator winding is connected to the line at higher slips and the excitation is applied immediately after the blocking contacts of the generator switch have been closed, the use of an excitation forcing device may increase the amplitude of swings [7-6].

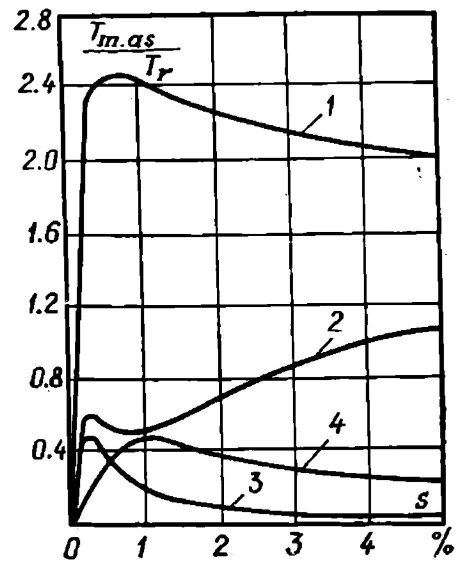


Fig. 7-12. Mean asynchronous torques of various types of synchronous machines

T_r — rated torque corresponding to generator power rating; *1* — for turbogenerator; *2* — for hydroelectric generator with damper windings; *3* — for hydroelectric generator without damper windings; *4* — for hydroelectric generator without damper windings when $R_{damp} = 5R_{rot}$ (R_{rot} — resistance of rotor winding; R_{damp} — damping resistor)

Due to the above, the excitation regulation and forcing devices are usually put into operation after the beginning of the self-synchronizing process and the excitation is generally applied at a relatively small slip, up to $\pm$ 5 per cent. If the connection of the generators by self-synchronization is promoted with the excitation being applied only at slips less than ± 3 per cent, the excitation regulation and excitation forcing devices may be always connected to the excitation circuits of the generator.

7-4. Automatic Connection of Generators by Self-Synchronization

The devices for automatic connection of the generators by self-synchronization are used as starting elements for hydroelectric generators, wind-driven

* From the shutdown state hydroelectric generators having damper windings may be pulled to a hyposynchronous speed under the effect of an asynchronous torque when the gate apparatus is closed. The speed-up time of a hydroelectric generator lies within 8 to 12 s.

generators, and engine-powered generators. With turbogenerators, automatic starting devices from the cold state are not used, since the bringing of a generating unit into operation needs considerable time to warm up the turbine. However, the devices for automatic connection of the generator by self-synchronization may be applied at thermal stations to facilitate the connection of a warmed up machine or together with the ARC devices of the generators after a short-circuit fault on the busbars has been cleared and the ARC devices are operative.

With a short circuit on the busbars the generators and the lines are disconnected. The ARC device connects the busbars from the system side. If the reclosure is successful and the busbar voltage is recovered, the normal circuit of the power station is completed after connection of the tripped generators. For this, use may be made of an automatic self-synchronization device. The generators are reconnected one after another after the speed has decreased to a value suitable for self-synchronization.

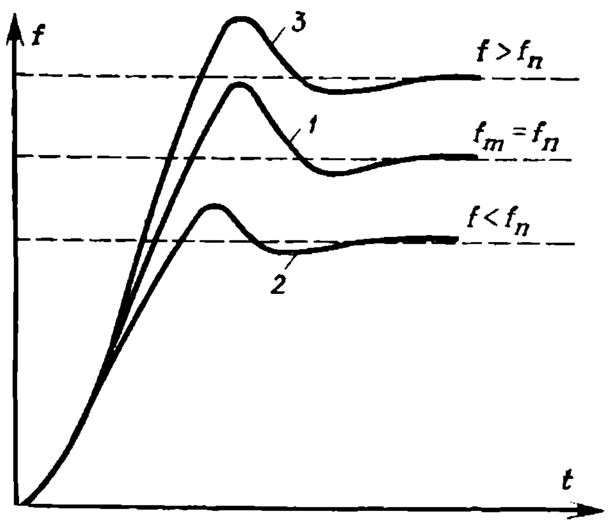


Fig. 7-13. Starting characteristics of hydroelectric generator

It should be noted that the tripped generators may be reconnected also by the precise synchronization method by using the ACT-4 autosynchronizer considered in the foregoing section.

Given below is a typical circuit of a device which automatically reconnects the tripped generators by self-synchronization. The circuit is designed to be applied to hydroelectric generators being started according to the centre characteristic and may be used for starting hydroelectric generators being started to the lowered characteristic.

The starting characteristic of a hydroelectric generator in this case is understood as the relationship between speed and time from the instant the control signal is given. This characteristic is determined by the type of turbine, position of the turbine speed-adjusting mechanism, initial opening of the gate apparatus and the characteristic of the speed governor.

Figure 7-13 illustrates typical starting characteristics of hydroelectric generators for different positions of the turbine speed-adjusting mechanism with the gate apparatus in the same position. Curve *1* corresponds to the centre position of the speed-adjusting mechanism, curve *2*, to the lower and curve *3*, to the upper position. The excitation is best applied at lowered speeds in the region of approach to the synchronous speed. In this case the generating unit quickly pulls in synchronism by increasing its speed under the effect of the asynchronous and synchronous torques.

Hydroelectric generators are most often started against the centre or lower curves. Starting against the centre characteristic is advisable if the accelera-

tion of the generating unit does not exceed the value at which the unit pulls in step after application of excitation without prolonged swings, otherwise starting is performed against the lower characteristic with subsequent operation of the speed-adjusting mechanism to speed up the loading of the generating unit.

When starting against the centre characteristic, the starting position of the opening control mechanism is found experimentally and when starting against the lower characteristic, it is set in the normal starting position. In the former case the speed-adjusting mechanism is set so that the machine may be accelerated to about 101 per cent of the rated speed under no load conditions at the minimum practicable head, and up to 80 to 90 per cent in the latter case.

A frequency-difference relay or a speed relay is used as the slip indicator. The circuit of the device for automatic connection of generators by self-synchronization (Fig. 7-14) utilizes a frequency-difference relay, type ИРЧ-01. Semiconductor frequency-difference relays may also be used.

To automatically start the generating unit, the duty key *1DK* is operated to start automatic self-synchronization device and close contacts *1CK-1* of the contactor *1CK* or the contacts of the starting relay.

Automatic starting of the unit will take place if the stop relay *StR* is deenergized and its contact *StR-1* is closed, the braking system of the generating unit is in good condition, the contact of the pressure transducer *PT* is closed, the excitation is removed from the machine, the *AFD* device is isolated with contact *AFD-1* closed, and the main switch is in the *OFF* position with its blocking contact *BC-1* closed.

After the starting signal has been given, the relay *SR* closes and holds itself with the contact *SR-1* as the starting pulse may be short-time. The coils of the frequency-difference relay *FDR* are closed by the contacts *SR-2* and *SR-3*. Simultaneously the contact *SR-4* turns on the turbine starting device via the automatic process control circuit.

When the machine reaches the hyposynchronous speed and the slip becomes equal to the setting of the frequency-difference relay (1 to 1.5 Hz) it will make its contacts. Since the contact making may be accomplished in a pulse-like manner (ИРЧ-01 relay), use is made of a pulse pickup relay *PR* which holds itself with the contact *PR-1*, while its contact *PR-2* breaks the circuit of one of the coils of the frequency-difference relay, the coil being connected to the voltage transformers of the generator. The contact *PR-3* closes the switch. The relay *PR* has a reset delay when its coil is deenergized.

After the switch is set to *ON*, the blocking contacts *BC-2* and *BC-4* close, the contacts *BC-1*, *BC-3* and *BC-5* open. The contact *BC-1* opens the circuit of the coil of the relay *SR* and it will reset.

The contact *BC-2* turns on the *AFD* device. The contact *BC-4* prepares the circuit of the trip coil, while the contact *BC-5* breaks the tripping circuit of the *AFD* device. After the relay *SR* is deenergized, the entire device will reset. The relay *PR* becomes released and 0.2 to 0.3 s later the closing circuit of the

switch will open and the closing circuit of coil *I* of the frequency-difference relay *FDR* will be prepared.

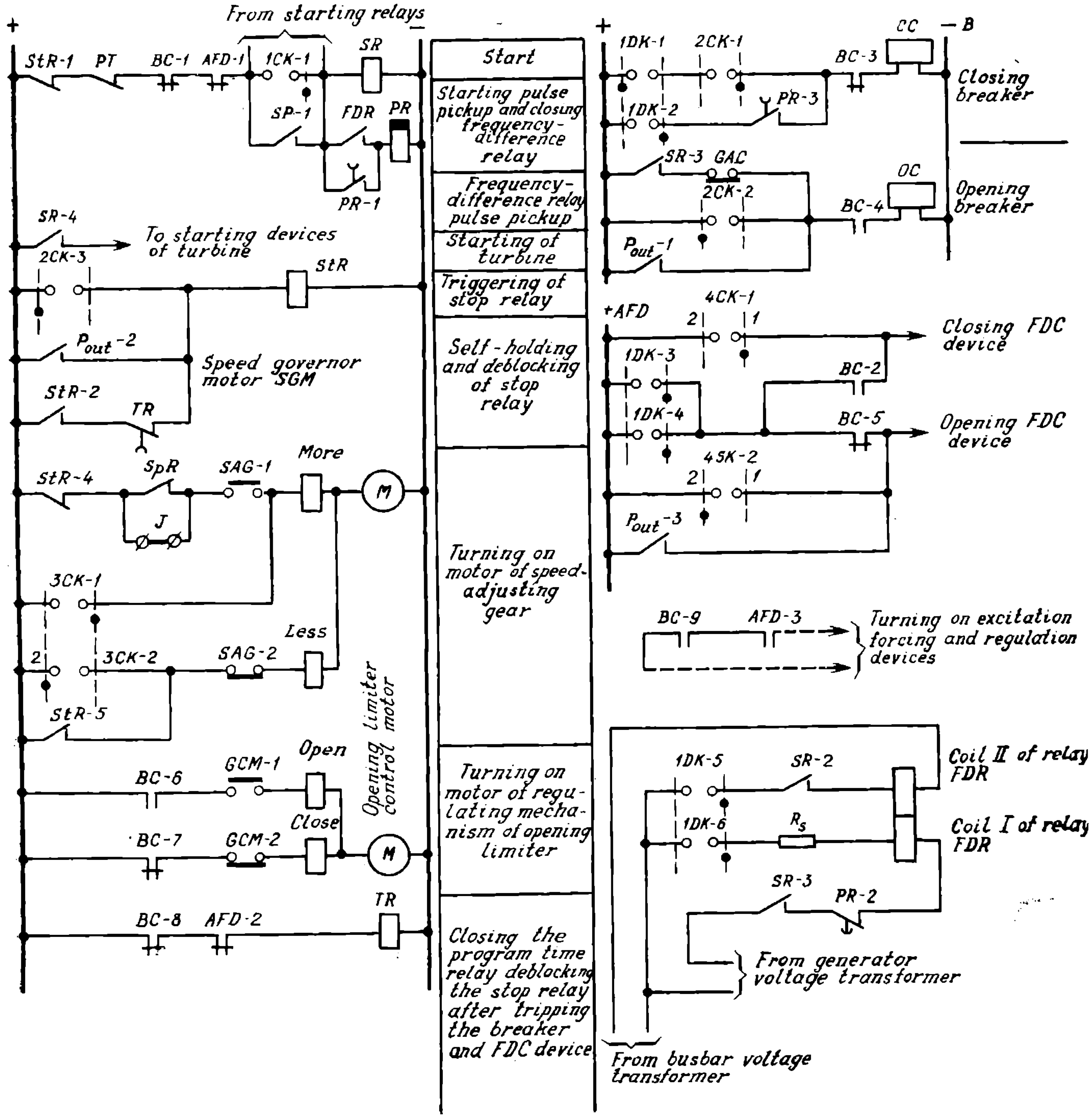


Fig. 7-14. Automatic self-synchronization of hydroelectric generators

After the switch is closed, the blocking contact *BC-6* will turn on the motor of the gate control. The gate control gear moves until the limit switch *GCM*-operates, this is set in compliance with the load dictated by the automatic

loading requirements and set by the power regulators. If the generating unit is at fault, the stop relay *StR* functions. This relay also functions when the generator is tripped manually with the aid of the contactor *2CK* (by closing the contact *2CK-3*) or when the output protection relay P_{out} operates.

The relay *StR* holds itself with the contact *StR-2* until the stopping process controlled by the time relay *TR* is completed.

The contact *StR-1* opens the starting circuit. The contact *StR-3* prepares the opening circuit of the main switch. This circuit is controlled by the contact of the gate apparatus *GAC* so that the opening pulse is given after the speed-adjusting gear has made the gate apparatus occupy the no-load position.

The contact *StR-4* breaks the "more" circuit of the motor of the speed governor *SGM*. The contact *StR-5* makes the "less" circuit. The speed governor starts to close the gate apparatus until operation of the limit switch of the speed-adjusting gear *SAG-2*.

The *SAG-2* contact opens when the gate apparatus is in the no-load position. By closing the *GAC* contacts a pulse is fed to open the switch. When the switch is opened manually by closing the contactor of contact *2CK-2*, or when opened by the protection contact P_{out}, the breaking circuit of the generator switch closes immediately without waiting for the gate apparatus to move to the no-load position.

After the switch is opened, the blocking contact *BC-6* opens the "opening" circuit of the gate control motor and the contact *BC-7* closes the "closing" circuit.

After the gate apparatus of the turbine has reached the starting "position" the contact of the limit switch *GCM-2* opens the circuit of the motor. As this happens, the contact of *SAG-1* closes with the effect that after the resetting of the relay *StR* and closure of the contact *StR-4* the speed-adjusting gear is set in the position in which the generator can reach the rated speed.

The limit switch of the *SAG-1* is so adjusted that it opens the supply circuit of the speed-adjusting gear motor, when the speed is somewhat greater than the rated value. The relay *StR* resets after the shutdown process of the generating unit is completed, this is controlled by the setting of the programming time relay *TR*. This relay closes after the switch has opened (after the contact *BC-8* has closed) and the AFD device has been tripped (the *AFD-2* contact has been closed).

The contacts of the speed relay *SpR* are placed into the circuit if the starting operation is accomplished against the lower characteristic. In this case the jumper *J* is removed. The speed relay is adjusted to a setting of 85 to 95 per cent of the rated speed and the limit switch of the *SAG-1* is adjusted so that it closes in a position corresponding to 80 to 85 per cent of the rated speed.

Shown by the dashed line in Fig. 7-14 are the circuits for connecting the *AEC* devices after the contacts *BC-9* and *AFD-3* are closed, i.e., after the switch and the field discharge automatic device have been closed. To control the *AFD* device manually, a contactor *4CK* is used.

7-5. Speed Control Methods

With the circuits for automatic connection of generators by self-synchronization the difference between the frequencies of the incoming unexcited generator and the line is most often controlled by means of a frequency-difference relay. When generators are connected by the self-synchronizing methods manually, double frequency meters, connected to the voltage to be measured via voltage regulators, may be used.

In many cases the frequency-difference relay may be connected to the voltage transformers without voltage regulators, since the value of residual voltage from the side of the unexcited generators is sufficient for proper operation of the relay, and the frequency-difference relay, type ИРЧ-01, functions if the voltage of the line is nominal.

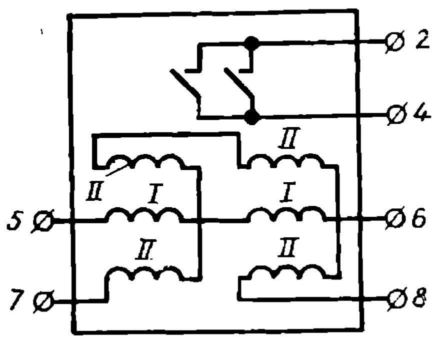


Fig. 7-15. Connections of relay ИРЧ-01

For the circuit of the ИРЧ-01 relay see Fig. 7-15. Coil *I* is connected through terminals *5*, *6* to the voltage transformer of the generator. The operating current of the coils is 55±±15 mA and the resistance of the coils is 0.15 Ohm. The current in the circuit of coils *I* is controlled by a rheostat having the range of 0-160 Ohm. The rheostat is designed to carry a current of 220 mA for 15 minutes. If the residual voltage of the generator fails to promote proper operation of the frequency-difference relay, coil *I* is connected through a voltage regulator. Through terminals *7* and *8* coils *II* are connected to the voltage transformers at the line end. The rated voltage is 100 V. The drawn power at the rated voltage is 35 VA. When the voltage across coils *II* and current in coils *I* change, the pickup setting spontaneously varies within the limits of 1.8 to 0.35 Hz, a disadvantage of the design which is now remedied. The manufacture of a semiconductor relay, type РРЧ, is now underway.

The frequency-difference relays in the circuits for automatic self-synchronization may be replaced by a speed relay. Sometimes, such a relay is installed additionally, like when starting against the lower characteristic.

A voltage relay supplied from an auxiliary synchronous generator carried by the rotor shaft of the main generator can be easily used as a speed relay. Such a generator is called a tacho-generator. It may supply the coils of the frequency-difference relay as well. The auxiliary a.c. tacho-generator has a rotor with permanent magnets. The emf of this generator is directly proportional to the rotor speed and the changes in the emf may be indicative of the speed of the generating unit.

When in service, care should be exercised to prevent demagnetization of the permanent magnets. The relay setting should be corrected in due time or the magnets must be remagnetized.

The speed may also be controlled by means of centrifugal relays or relays supplied from a d.c. tacho-generator. The exciter of the main generator is sometimes used as such a tacho-generator. The slip is controlled by a relay responding to the a.c. component of the rotor current.

With the approach of the speed to the synchronous value, the ripple cycle of the alternating current in the rotor circuit increases. Therefore, if an intervening transformer is placed in the field coil circuit with its secondary winding connected to a delayed reset relay, operation at the required slip is obtained by changing the setting and reset time.

Another possibility of using a slip relay employing a variable component of the current in the rotor circuit is shown in Fig. 7-16. Rectified current is

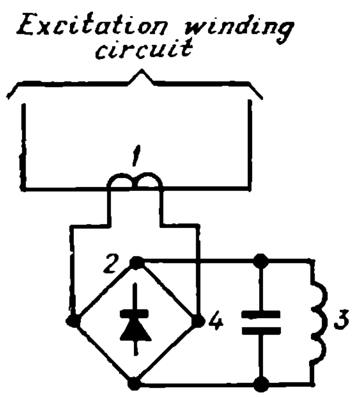


Fig. 7-16. Connection of slip relay
1 — current transformer; 2 — rectifier; 3 — relay coils; 4 — capacitor

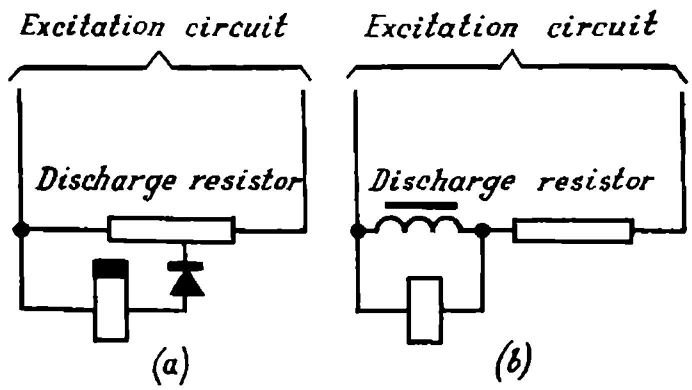


Fig. 7-17. Circuits of slip control relay
(a) delayed reset relay connected to part of discharging (damping) resistor; (b) relay connected to additional choke

fed to the relay. The greater the slip, the greater the active value of this current. When the speed approaches the synchronous value, the current decreases and the relay functions.

Figure 7-17 shows the versions of the slip control circuits used in the starting devices of synchronous motors and synchronous capacitors. The delayed reset relay (Fig. 7-17*a*) carries pulsating current obtained by a.c. half-wave rectification. To reduce the rate of magnetic flux decay, the relay magnet is furnished with a copper sleeve or the relay coil is additionally energized through a capacitor. Here, the magnetic flux in the magnetic system of the relay disappears but not at once and the relay reset time finally depends on the amount of slip.

The relay in the circuit shown in Fig. 7-17*b* is connected in parallel with the choke wired in series with the discharge resistor of the field winding.

The higher the frequency of the alternating current in the field coil circuit (the inductive reactance of the choke is directly proportional to the frequency), the higher the voltage across the choke terminals. When the slip is at a value corresponding to the reset voltage setting of the relay, the armature drops out and the contacts carry out the required operations.

7-6. Asynchronous Connection of Generators and Parts of Power System

If an *excited* generator, whose emf is E_g (see Fig. 7-4), is connected to the power system busbars under asynchronous conditions an equalizing current arises at the instant of connection

$$I_{as}=\frac{\Delta E}{x''_{dg}+x_s} \tag{7-25}$$

[compare with (7-18) for an *unexcited* generator].

When $E_g = E''_d = U_c$

$$\Delta E=2E''_d\sin\frac{\delta}{2}=2U_c\sin\frac{\delta}{2} \tag{7-26}$$

In expressions (7-25) and (7-26)

ΔE = vector difference between the emf of an asynchronously connected generator, after the direct-axis (inrush) supertransient inductive reactance voltage E''_d, and the circuit voltage U_c

x''_{dg} = direct-axis supertransient (inrush) inductive reactance

x_s = inductive reactance of the power system

The asynchronous connection current is at its maximum when the generator is connected in opposition to the emf of an equivalent generator of the power system. With asynchronous connection to an infinite-power system ($x_s = 0$) having angle $\delta = 180$ degrees

$$I_{as\,m}=\frac{2E''_d}{x''_{dg}} \tag{7-27}$$

The short-circuit current in the case of a three-phase short circuit at the generator terminals

$$I_{s.c}=\frac{E''_d}{x''_{dg}} \tag{7-28}$$

It is seen from (7-27) and (7-28) that the maximum asynchronous connection current may be twice as great as the current during a short circuit across the stator winding terminals.

The asynchronous connection currents cause considerable forces to arise which affect the shaft and windings of the generator stator, synchronous capacitor, and transformer windings. Synchronous machines are designed to withstand impact currents of three-phase short circuits at the stator terminals with the rated speed and a voltage equal to 1.05 of U_n.

Thus, as dictated by the generator safety requirements, the criterion of acceptable asynchronous connection is represented by the magnitude of the mechanical forces affecting the generator. The values of these forces should not exceed those resulting from three-phase short circuits at the generator terminals. Investigations [7-8] show that the magnitude of the arising electromagnetic torque is the decisive factor of asynchronous connection. For con-

venience, the practical calculations of the permissible torque multiplicity factors (acceptable asynchronous connection) are carried out through the multiplicity factors of the periodic component of the asynchronous connection current at the most unfavourable angle $\delta = 180$ degrees relative to the nominal current.

The calculation of the maximum value of the periodic component of stator current in asynchronous connection ($I_{as.m}$) is performed from the assumption that $E_1 = E_2 = (1.05 - 1.1)\ U_{ph.n}$

$$I_{as.m} = 2\frac{(1.05-1.1)\,U_{ph.n}}{\Sigma x_{\text{I-II}}} \tag{7-29}$$

where 2 = coefficient which accounts for the emf vectors being 180 degrees apart

$U_{ph.n}$ = nominal phase voltage

$\Sigma x_{\text{I-II}}$ = mutual reactance of the equivalent circuit in which the generators are represented by the supertransient reactance x''_d

To comply with the circular determining the field of application of automatic reclosure in power systems [7-9], the attending personnel have to manually perform immediate reverse asynchronous connection of the tie lines if the ARC device did not operate or was not installed on them. A certain multiplicity factor of the asynchronous connection current relative to the nominal current is a condition of expediency of the asynchronous connection for a particular purpose.

The above-mentioned multiplicity factor should not exceed:

$I_{as}/I_n \leqslant 0.625/x''_d$, for turbogenerators and hydroelectric generators having damper windings; $I_{as}/I_n \leqslant 3$, for turbogenerators with direct cooling of the windings and for hydroelectric generators without damper windings; $I_{as}/I_n \leqslant 0.84/x''_d$, for synchronous capacitors; and $I_{as}/I_n \leqslant \frac{k\,100}{e_{s.c}+p}$, for transformers; k is a coefficient accounting for an increased value of emf resulting from asynchronous connection; $k = 0.85$ for hydroelectric generators, $k = 0.95$ for turbogenerators; and $k = 1.0$ for turbo-and hydro-generators when the emf rises but by not more than 5 per cent; $p = 100\frac{S_{tr}}{S_{s\cdot c}}$, $e_{s.c}$ is a short-circuit voltage of a transformer, per cent; S_{tr} is the transformer power in MVA. The values of $S_{s.c}$ are determined as follows:

Short-Circuit Power Versus System Voltage

System voltage U_n, kV . . .	Up to 6	10-35	110
Short-circuit power S_{sc}, MVA . .	1000	1500	5000
System voltage U_n, kV . . .	220	330	More than 330
Short-circuit power, S_{sc}, MVA	10,000	15,000	25,000

The circular [7-9] draws attention to the fact that sometimes asynchronous connection of the lines, determined by satisfying only the above-touched upon

requirements, may cause prolonged asynchronous operation which should be eliminated by attending personnel as specified in special instructions. The circular also states that, if the asynchronous connection current multiplicity factor calculated by the above expressions prove to be greater than the permissible values, more precise computations must be made to take into account the load. Usually the permissible asynchronous connections are calculated without taking into account the load.

From (7-27) it is clearly seen that asynchronous connection of a single generator to infinite-power busbars cannot be allowed. When $x''_d = 12$ per cent, for example, the ratio of asynchronous connection current relative to the nominal value is greater than 17. Asynchronous connection of generators performing a joint operation through a transformer and a transmission line, into a finite-power system, sometimes may be permitted.

If there is a group of paralleled generators, then often simultaneous synchronous connection of all the machines of the power plant or part of the power system may be permitted. The asynchronous connection current determined by (7-29) should be apportioned among the paralleled generators. When making calculations the minimum possible number of machines should be considered (i.e., the most severe case from the point of view of the current value used in asynchronous connection).

Asynchronous connection yields good results only when it is followed by rapid resynchronization of the generators or parts of the power system. Resynchronization is promoted, if the mean set-up slip (the frequency difference) between the asynchronously connected parts (generators) of the system is less than a certain "critical slip" which equals 1.5 to 2.0 Hz for connecting "directly" coupled parts, and 0.2 to 0.5 Hz for "indirectly" coupled parts of the power system. For the resynchronization calculation techniques see reference [7-8].

If for particular services asynchronous connection is permissible measures should be taken in order to prevent unwanted operation of various protection means under these operating conditions (see Sections 4-7 and 8-3).

In complicated power systems asynchronous connection may sometimes cause objectionable tripping of the loads located near the electric centre and sometimes it may pull other paralleled power plants out of synchronism. Therefore, parts of the power system in which asynchronous connection may be applied should be planned beforehand with a preliminary analysis to see whether such connection is suitable for the load operating conditions, resynchronization of the parts of the power system (generators) and operation of the protective relaying.

Under emergency conditions, asynchronous connection performed with a small frequency difference and with protective devices which do not function during asynchronous operation or are isolated against such operation by the operating setting or time of action may materially facilitate the recovery of the normal performance of the power system.

The time needed for the recovery of normal operating conditions after asynchronous connection is also dependent to a considerable extent on how quickly the normal operation of the loads, including the asynchronous and

synchronous motors, is restored. The asynchronous laod should restart by itself, after the voltage restoration.

The next section discusses the problems of keeping synchronous motors in operation and their resynchronization after they are pulled out of step.

7-7. Connection of Synchronous Motors, Preventing Their Drop-Out of Step and Resynchronization

Let us consider the performance processes in the so-called "direct" starting of rated-loaded synchronous motors [7-3]. By direct starting is meant starting a shutdown generating unit with full voltage by a switch without a

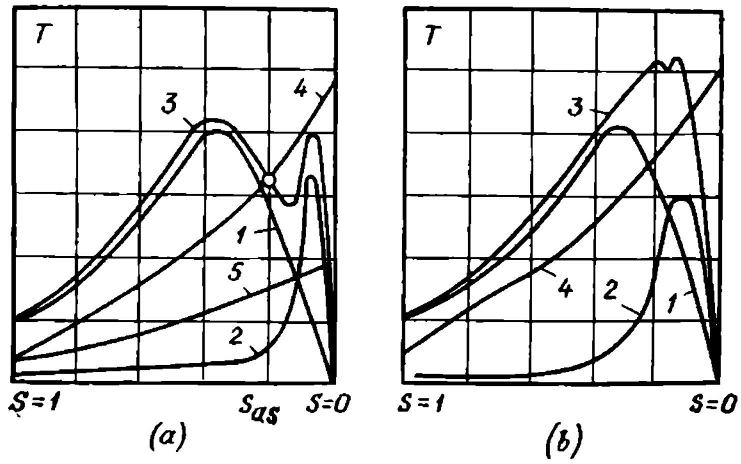


Fig. 7-18. Starting characteristics of synchronous motors
(a) without connecting resistance into rotor winding circuit; (b) when resistance is connected

starting device when the exciter is directly connected to the rotor winding of a synchronous motor. When a loaded synchronous motor is energized it will start to revolve due to the asunchronous torque resulting from the currents induced in the rods of the starting cage and in the rotor core. The characteristics of the starting torque are shown in Fig. 7-18, curve *1*.

When the motor speed increases and approaches the hyposynchronous speed an additional asynchronous torque occurs, which is due to the rotor winding being shorted to the exciter or another source of direct current. This torque is shown by curve *2* in Fig. 7-18*a*. The total starting torque has the characteristic shown by curve *3*. When the motor reaches the hyposynchronous speed, the synchronous torque forces it into synchronism.

It is seen from Fig. 7-18*a*, that the hyposynchronous speed can be reached if the anti-torque (curve *5*) is less than the total starting torque within the entire range from $s = 1$ to $s = s_i$ (point where curves *3* and *5* intersect).

If the anti-torque has a value corresponding to curve *4* the motor will fail to reach the hyposynchronous speed and will not be pulled in step. The result will be prolonged asynchronous operation with a mean slip determined by the

abscissa of the intersection point of curves *4* and *3* ($s = s_{as}$). In this case the motor can be pulled in step either by reducing the anti-torque, i.e., by unloading the motor from the side of the driven mechanism or by increasing the ordinates of the starting torque.

In circuits with reactor starting, the increase in the starting torque ordinates of a synchronous motor in the vicinity of the hyposynchronous speed is obtained by removing the starting reactor from the circuit supplying the stator. This is accomplished by the automatic starting devices.

Another way of increasing the total value of the starting torque is to increase the resistance of the rotor circuit of the synchronous motor by connecting a resistor into it for the time of starting. Because of this, the maximum of the torque produced by the closed winding of the rotor becomes displaced towards the increased values of slip and, as seen from Fig. 7-18*b*, conditions are created which promote pulling the motor in step without reducing the anti-torque.

The value of the resistor connected for the starting period in series with the rotor winding is 3 to 5 times the R_{rotor} (R_{rotor} is the resistance of the rotor winding when warmed up) [7-12].

The operations used to connect and disconnect the above-mentioned resistance can be performed by the automatic starting devices both when the rotor is supplied from a d.c. exciter and when a thyristor excitation circuit is used. In the latter case the operations are accomplished by semiconductor devices.

If, when starting a synchronous motor, the rotor winding is disconnected by the field discharging automatic device from the d.c. source and connected to a damping resistor, the motor will be pulled in step in the same way as a generator connected by the self-synchronizing method, i. e., until the hypo-synchronous speed is reached the motor is accelerated at the expense of the asynchronous torque and then the automatic starting devices change over the rotor winding from the damping resistor to a d.c. source [7-4, 7-13].

The motor remains in synchronism if the shaft load does not exceed the synchronous torque with angle $\delta = 90$ degrees, i.e., when the motor is supplied from the substation busbars

$$P_{load} < \frac{E_m U_n}{x_{1-b}} \tag{7-30}$$

Usually the maximum power developed by a synchronous motor (P_m) is approximately two times the motor load (P_l). In this case, normal operation of a synchronous motor takes place with angle $\delta_{12n} = 30$ degrees (Fig. 7-19*b*). With other relationships between P_{load} and P_n

$$\frac{\delta_{load}}{\delta_n} \approx \frac{P_{load}}{P_n} \tag{7-31}$$

During a short circuit in the external power supply circuit the busbar voltage of the supplying substation of the power system drops. As a result, the

synchronous torque decreases. Due to the mechanical load and electrical losses the rotor of the motor starts decelerating and the angle δ begins increasing. The process continues until the short circuit is cleared and the voltage restored.

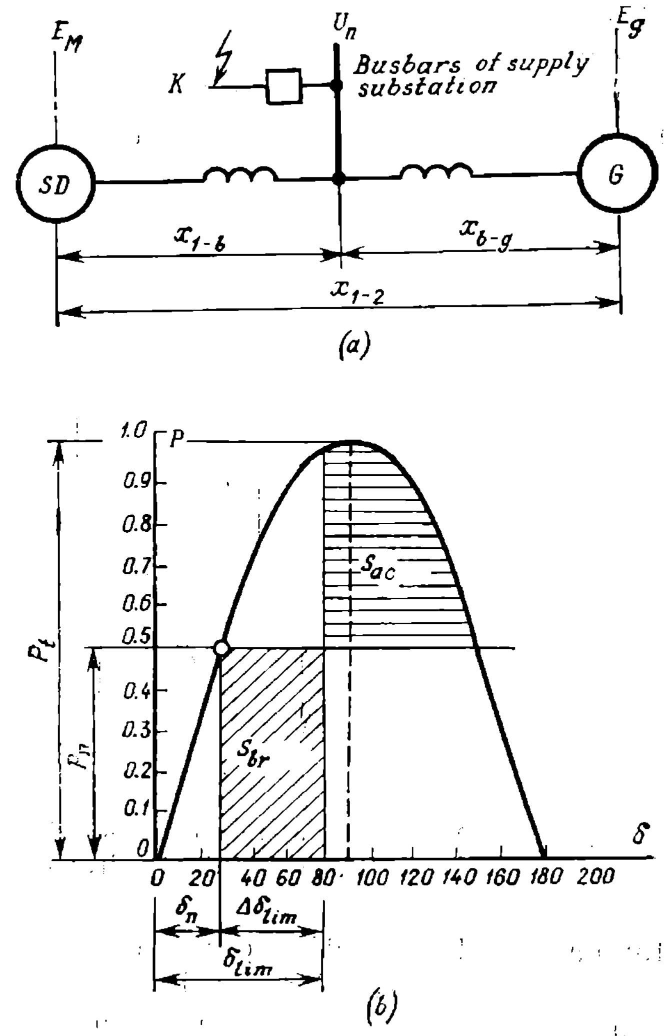


Fig. 7-19. Supply circuit diagram (*a*) and power characteristics (*b*)

If a three-phase short circuit occurs at point K and the residual voltage across the substation busbars equals zero, the electric power drawn by the motor also becomes equal to zero.

As the mechanical power (anti-torque) exceeds the electrical power, the motor decelerates. If the resistive losses in the short-circuit network are neglected the energy consumed in braking is proportional to the area S_{br} (Fig. 7-19*b*) and determined by the mechanical load (with due consideration to the efficiency of unit).

The motor does not drop out of step if, after clearing the short circuit, the acceleration area S_{ac} (here the synchronous torque is greater than the anti-torque and the motor accelerates) equals or exceeds the braking area S_{br}. The short-circuit clearing time, when the stability is maintained and the motor does not drop out of step, is determined by the expression

$$t_{lim} = \sqrt{\frac{\Delta\delta^{\circ}_{lim} T_{in}}{9000}} \qquad (7\text{-}32)$$

The value of δ_{lim} may be calculated by a graphical-analytical method provided the condition $S_{ac} \geqslant S_{br}$ is satisfied.

From Fig. 7-19*b* it is seen for the instance being considered, that δ_{lim} corresponding to the condition $S_{ac} = S_{lim}$ is

$$\delta_{lim} = 79^{\circ}$$

and

$$\Delta\delta_{lim} = 79^{\circ} - 30^{\circ} = 49^{\circ}$$

If for the mechanism $T_{in} = 4$ s, then from (7-32) $t_{lim} = 0.148$ s; when $T_{in} = 3$ s, $t_{lim} = 0.128$ s; and when $T_{in} = 2$ s, $t_{lim} = 0.105$ s.

It is clear now that the principal way to hold synchronous motors in step is the rapid clearing of short circuits.

The time limit of clearing a short circuit will be greater if, during a short circuit, the voltage across the terminals of the synchronous motors supplied through the unfaulted sections of the power system is other than zero. When the residual voltage is of the order of 0.65 U_n the short-circuit clearing time limit may run to 1 to 1.5 s, the time being governed by the permissible time

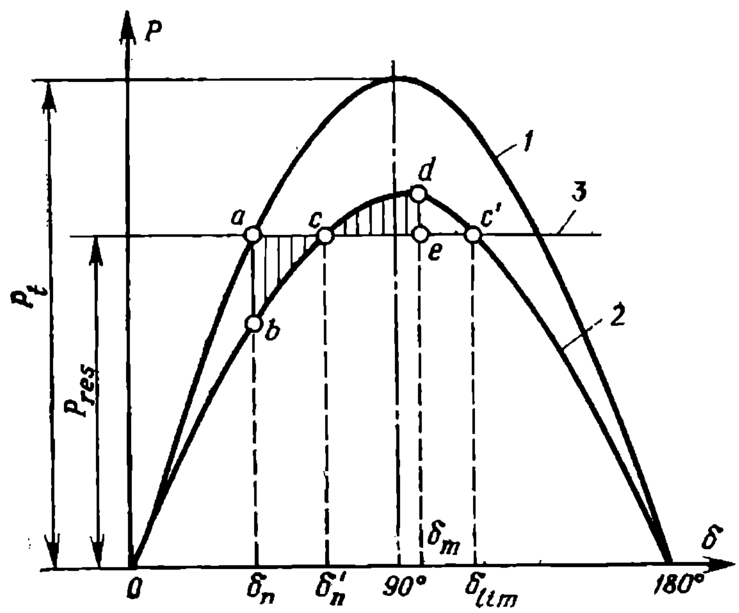


Fig. 7-20. Power characteristics when terminal voltage of synchronous motor stator suddenly drops to 65 per cent of rated value

for passing the starting currents. In this case, the braking area is less than the accelerating area (Fig. 7-20). When $U_{1\ res} = 0.6\ U_n$ and E_d is constant the braking and accelerating areas are equal to each other.

Another way to increase the short-circuit clearing time limit is not to fully load the motor. If P_{load} is less than P_n the value of the limited angle δ_{lim} ($\Delta\delta'_{lim} > \Delta\delta_{lim}$) increases and at the same time the possible braking area decreases.

In this case

$$t_{lim} = \sqrt{\frac{\Delta\delta'^{0}_{lim} T_{in}}{9000}} \sqrt{\frac{P_n}{P_{load}}} \qquad (7\text{-}33)$$

If the short-circuit clearing time exceeds the above values and the duration of heavy voltage drops is greater than t_{lim} the synchronous motors will drop out of step. The synchronism may also be disturbed by interruptions in the power supply during the automatic reclosure cycle or the automatic cut-in cycle of reserve supply with the no-current time ranging from 0.5 to 2.0 s.

In addition to preventing the dearrangement of synchronous generators, the necessity to ensure continuity of a production process dependent on the

operation of units including synchronous generators calls for rapid resynchronization of the motors after recovery of the power supply.

Rapid resynchronization is obtained by the following methods.

Asynchronous connection of excited synchronous motors to the full voltage when the motors revolve under inertia with their field being not discharged after a short-time interruption in power supply.

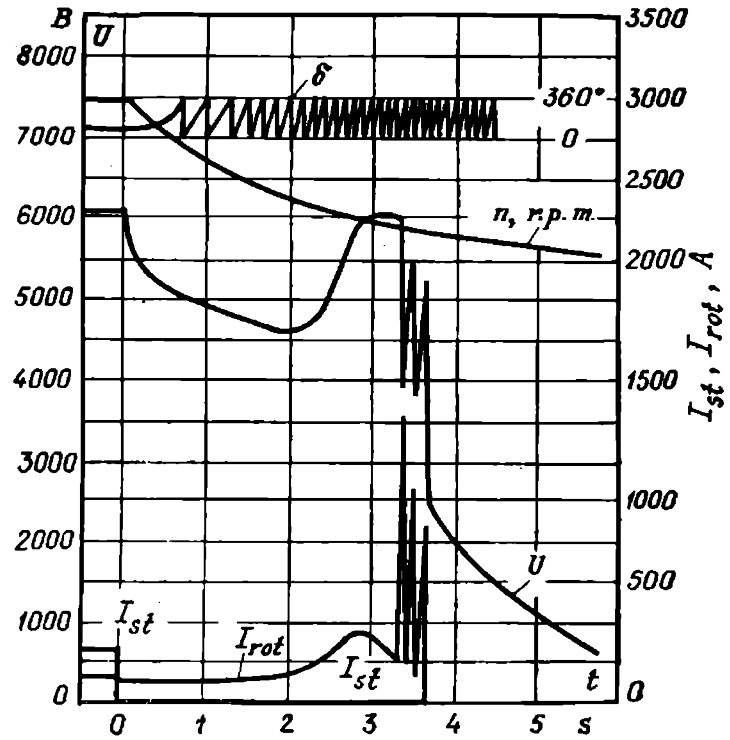


Fig. 7-21. Changes in currents, voltages and speed of synchronous motor when it is deenergized (motor, type CTM-3500-2)

I_{st} and I_{rot} are stator and rotor currents; U — voltage across stator terminals; n — speed

The method holds when two conditions are satisfied. First, the asynchronous connection currents must not cause mechanical damage to the motor and, second, the characteristics of the starting torques and the anti-torque should allow the motor to pull in step without being held at a hyposynchronous speed.

The emf decay of a synchronous motor disconnected from the power source and revolving due to its inertia is seen in Fig. 7-21.

After the effect of forcing the excitation the terminal voltage of the motor almost reaches for some time the nominal value [7-4]. Whether the asynchronous connection is acceptable as to the mechanical safety of the motor may be determined from equations given in reference [7-14]. For a very rough estimation we may take the statement [7-14] that, as to the mechanical safety, a synchronous motor may be connected to a full voltage after discharging the

field. Under such conditions, the residual value of the emf lies within 0.5 to 0.6 U_n.

Assuming, for the sake of safety, that the residual permissible emf of the motor $E_{m.perm} = 0.4U_n$, we find that the equalizing current in the opposition phase should not exceed

$$I_{eq.\,m} \leqslant \frac{1.4U_{ph.\,n}}{x''_d} \qquad (7\text{-}34)$$

If this current is taken as the maximum permissible for asynchronous connection then, with the reactance of the supplying system x_s and under the conditions when $E_m = U_{ph.n}$, the following relationship should be followed

$$\frac{1.1 \cdot 2 \cdot U_{ph.n}}{x''_d + x_s} = \frac{1.4U_{ph.n}}{x''_d} \qquad (7\text{-}35)$$

where 1.1 = safety factor

x''_d = supertransient reactance of the motor

From (7-35) it follows, as dictated by the mechanical safety of the motor, that connection with the field not discharged is permissible, after a short-time interruption in power supply during no-current intervals in ARC or automatic transfer whenever

$$x_s \geqslant \frac{2.2 - 1.4}{1.4} x''_d$$

i.e., when

$$x_s \geqslant 0.57x''_d \qquad (7\text{-}36)$$

When power supply fails or the motor synchronous operation is disturbed the motor field should be discharged. To increase the starting torque a resistor is placed in the rotor winding circuit. After recovery of the supply voltage, the automatic starting devices apply the excitation and the motor is pulled in synchronism in a way similar to that in the normal start of the motor [7-14].

To facilitate resynchronization, the driven mechanism should, when necessary, be unloaded for a short period [7-15].

Failures of power supply from the power system can be indicated in different ways. The most simple is to use an underfrequency relay and an active power-directional relay. The latter changes the position of its contacts and acts upon the automatic starting devices when the power supply fails [7-4]. The use of an active power-directional relay in conjunction with an underfrequency relay as a detecting element has been justified in service.

Like the forward-sequence voltage relay whose purpose is to control the duration of short circuits in the supplying circuit, the action of the above-mentioned relays must take place only when the synchronous motor loses synchronism. To this end, the devices detecting interruptions to the normal power supply are given a small time delay whose value is determined from equations (7-32) and (7-33).

7-8. Conclusions

1. In cases of emergency, rapid paralleling of generators or parts of the power system may sometimes prevent the fault developing and facilitate its elimination.

2. Manual connection of generators by precise synchronization without automatic controls requires much time and attention on the part of the attending personnel. Automatic precise synchronization eases the operator's work, facilitates the synchronizing process and prevents incorrect actions by personnel. All this is of particular importance under emergency conditions. Therefore, the autosynchronizers must be at all times ready for operation and must provide trouble-free operation when the frequency and voltage of the power system vary.

The Soviet-developed autosynchronizer, type ACT-4, largely fulfills these requirements.

3. Connection of generators by the self-synchronizing method simplifies and facilitates the paralleling process, but it complicates the operating conditions of the synchronous generator. Each self-synchronization connection is equivalent to a short circuit after the x'_d point (in large power systems).

Under emergency conditions all the generators and synchronous capacitors may be connected by the self-synchronizing method regardless of type, construction, cooling system, power rating and commutation scheme.

4. It has been proved theoretically and in service that asynchronous connection of generators and synchronous capacitors is feasible and effective providing the ratio between asynchronous connection current and the nominal value does not exceed the value which is permissible for mechanical strength of the structure. These conditions are often fulfilled, when connecting generators through tie lines or transformers or when connecting parts of the power system.

5. To prevent possible prolonged asynchronous operations, asynchronous connection is better accomplished when the frequency of the incoming generators, or parts of power system, is close to the power system frequency.

The load-dispatching personnel and the operators of the power stations and substations should be instructed on the measures they should take if asynchronous connection is followed by prolonged asynchronous operation.

6. The points of the power system at which asynchronous connection is permissible must be planned beforehand and measures foreseen to prevent misoperation of the protective relaying system during asynchronous connection.

7. When determining the possibility of asynchronous connection of consumer synchronous motors, the starting method of those motors should be considered and the possibility of their resynchronization without the use of special automatic devices, or with the use of them, estimated. It is good practice to adapt the automatic starting devices of synchronous motors to the asynchronous connections, both in the power system and at the motor itself.

These automatic devices must promote resynchronization of the motor and maintenance of its load after removal of the causes that made it drop out of step.

7-9. Review Questions

1. What are the main specific features encountered in the paralleling of generators by the precise synchronization and self-synchronizing methods?

2. Explain how the current and voltage of a generator vary when it is connected by the self-synchronizing method? Why is connection of generators by these methods permissible under emergency conditions regardless of the type and capacity of a synchronous machine?

3. When paralleling machines, how is the automatic starting of hydroelectric generators accomplished with the use of the self-synchronizing method? Could hydroelectric generators be started by an automatic operator with the use of an automatic synchronizer, type ACT-4?

4. Name the basic elements of the ACT-4 autosynchronizer and explain their functions. Describe the operating principles of a differentiating transformer and a lead relay.

5. What is the difference between asynchronous connection of a group of generators and their connection by the precise synchronizing method?

6. Under what conditions is asynchronous connection of generators and parts of power system permissible?

7. How is the direct starting of synchronous motors accomplished?

8. What are the torques that make a synchronous motor pull in synchronism?

9. What causes prolonged asynchronous operation of the power system after asynchronous connection and what causes prolonged asynchronous operation when a loaded synchronous motor is asynchronously connected?

10. Under what conditions may asynchronous connection of a loaded synchronous motor be performed if it has been tripped from the power system for a short period?

11. Describe the methods used to hold synchronous motors in synchronism when short circuits occur in the circuit.

12. Describe the principles underlying the automatic starting devices of a synchronous motor which help its resynchronization after clearing the fault which caused the stability disturbance.

13. What are the factors that promote resynchronization of generators after their asynchronous connection?

14. Why is a voltage sustained across the stator terminals of a synchronous motor when it is disconnected from the supply source?

15. Why does a rotating unexcited generator maintain a voltage across the stator winding terminals after it is disconnected from the power system? What is the value of that voltage?

16. Can a generator be connected to infinite-power busbars by the self-synchronizing method? Can an excited generator be asynchronously connected to such busbars?

17. Why is asynchronous connection permitted for a group of simultaneously switched on generators operating in parallel and not permitted for connection of a single generator?

18. Explain the principles underlying a slip relay.

19. What are the methods of indicating interruptions in the power supply to a synchronous load?

20. What are the techniques used in the ACT-4 autosynchronizer to control the difference between the values of voltages being synchronized and how is the frequency of the machine being synchronized adjusted to suit the frequency of the power system?

21. Figure 7-22 shows the circuit for automatic starting and resynchronization of a synchronous motor[7-12]. The position of the equipment corresponds to the state when the motor is stopped and disconnected. Full-load starting of the synchronous motors is by switch *S*. Under the action of the starting asynchronous torque the motor and the driven mechanism begin to rotate. As the speed increases the terminal voltage of the exciter rises. The starting current flowing in the stator circuit makes the relay *SCR* function and its contact *SCR-1* closes the relay *1ATR* with delayed dropout of the armature when the coil is deenergized.

The contact *1ATR-1* closes the relay *2ATR*. Its contact *2ATR-1* closes and prepares the closing circuit of the excitation forcing contactor coil *1FK* and the contactor closing coil *K*. At the initial moment of starting the resistor R_{sh} is shunted by the contact of contactor *2FK*. The resistor R_{sh} is unshorted after the terminal voltage of the exciter reaches a value at which the contactor *2FK* operates.

When the motor reaches a hyposynchronous speed the current flowing in the stator decreases. The relay *SCR* resets. The contact *1ART-2* closes the forcing contactor *1FK* and contactor *K* (a contactor with a latch).

The forcing time is limited by the reset time of the relay *2ATR* which breaks the circuit by its contact *2ATR-1*.

Closing the contactor *K* (coil K_c) results in the closure of the contacts *K-1* which shunt the coil of relay *SCR*. This prevents operation of this relay in case of load surges. Closing

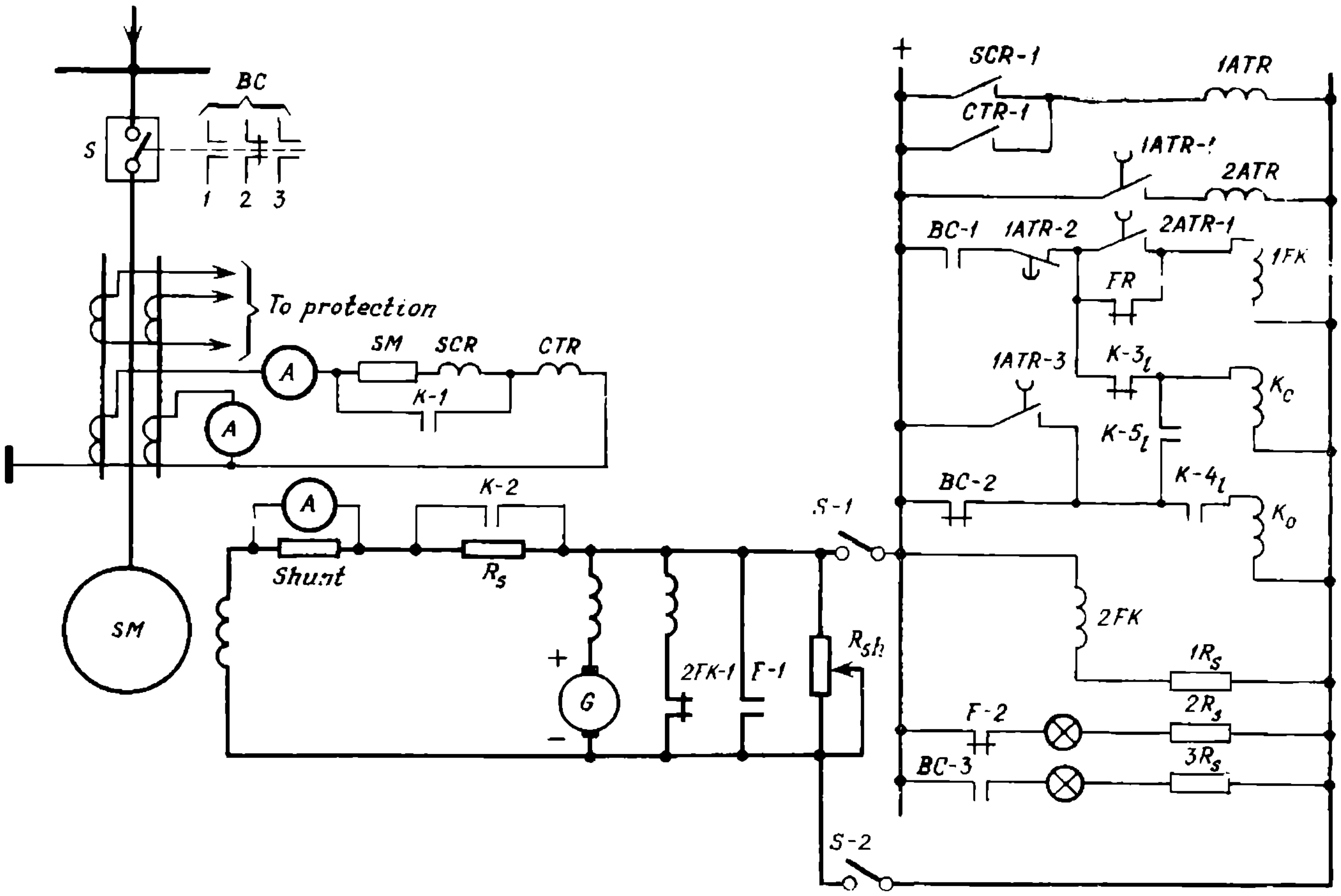


Fig. 7-22. Automatic starting and resynchronization of synchronous motor

the contact *K-2* promotes bypassing of the resistor R_s in the rotor winding circuit. The purpose of the resistor R_s is to increase the initial value of the starting torque and eliminate the dip in the starting characteristic when at hyposynchronous speed. After operation of contactor *K* the resistor R_s is isolated from the rotor circuit of the synchronous motor.

The contacts $K\text{-}5_l$ and $K\text{-}4_l$ prepare the circuits for opening the contactor *K* and releasing the latch. The contactor *K* is tripped either after the switch *S* is opened or after the operation of relay *1ATR* (when the contacts *BC-2* or *1ATR-3* make), i.e., in the conditions under which preparations are made for repeated reclosure of the motor.

The motor is shut down by opening the switch *S*. Its auxiliary contacts *BC-1* and *BC-3* break and the contact *BC-2* makes. The circuit promotes the resetting of the automatic devices for subsequent reclosures. To trip contactor *K*, the operative current must be fed to the coil K_c simultaneously with the sending of the tripping signal to the coil K_0. In this case, the closing solenoid becomes energized for a short time and releases the latch allowing the contactor to be tripped. After the contactor *K* has tripped the blocking contacts $K\text{-}4_l$ and $K\text{-}5_l$ will be opened and the contact $K\text{-}3_l$, closed.

When the motor operates and loses synchronism switch *S* does not open. After recovery of the normal power supply (for example, after clearing a prolonged short circuit in the power

circuit or after the ARC and automatic transfer devices have impressed voltage upon the stator winding) the motor will operate asynchronously. Under the effect of the equalizing current the relay *CTR* (dependent time-lag current relay) functions. 1 to 1.5 seconds later the contact *CTR-1* makes and the relay *1ATR* closes. After the closure of the contact *1ATR-3* and coil K_0 the contactor *K* trips.

Breaking the *K-2* contact places the discharge resistor R_s into the rotor circuit. The coil of *SCR* is unshorted by the contact *K-1*. The motor is started again.

Can the starting circuit shown in Fig. 7-22 be used for motors which do not allow asynchronous connection in a real circuit in order to avoid mechanical trouble?

What modifications or alterations should be made to the circuit shown in Fig. 7-22 so that the discharge resistor R_s is automatically introduced into the circuit when the motor power supply from power system stops as a result of operation of the ARC and automatic transfer devices?

22. A synchronous motor is provided with a thyristor excitation system supplied form a step-down transformer installed on the busbars used for the supply to the synchronous motor. Provisions are made to force the excitation when voltage drops by 15 per cent of the rated value.

Will the excitation forcing improve the stability of the paralleled motor during a three-phase short circuit accompanied by a voltage drop across the supplying busbars to zero?

Chapter Eight

THREE-PHASE AUTOMATIC RECLOSURE

8-1. General

The three-phase (three-pole) automatic reclosure (TPARC) devices, subsequently referred to as ARC devices, are designed to automatically close tripped elements of the power system in order to restore the consumer supply or complete their supply circuit.

1. *Automatic reclosure efficiency* is assessed by the ratio between the number of reclosures after which the affected equipment is not immediately disconnected, by the tripping of the protective relaying device, and the total number of reclosures performed by the ARC devices. The ARC efficiency results from the fact that the causes of tripping often clear themselves while the feeder is deenergized. Faults, such as whipping, stop and isolation is restored, the arc caused by lightning dies out and the overload which caused the protective relaying devices to function disappears.

2. *Correct and incorrect operation of ARC devices.* The correct operation of the ARC devices is assured by trouble-free operation both of the relaying part of the equipment and the switching device (breaker) used to reenergize the electrical circuit. Incorrect operation can be due to a failure of the ARC device itself or the breaker which fails to reclose because of a defect.

3. *Effectiveness of ARC devices* is determined by the amount of possible damage prevented by its operation in one year against the costs of their installation and maintenance. The most effective are the ARC devices installed on the breakers of incoming overhead feeders which are not automatically supplied from stand-by sources of power. This is the reason why the consumers can, most often, continue their operation after a short interruption in the power supply, in particular where measures are taken to promote self-starting of the loads.

During thunderstorms good results are obtained from the use of ARC devices installed on overhead lines. Most of swinging crosses occurring in such weather clear themselves after deenergizing the transmission line, and the operation of the ARC device restores the line service quickly.

Service experience has also proved the high efficiency of the ARC devices installed on busbars, since the short circuits occurring on busbars may also be unstable.

By virtue of the above, the use of ARC devices for reenergizing the lines, busbars and transformers becomes compulsory. Instruction circulars also stipulate immediate reclosure of the breakers of the above elements by personnel either

remotely by means of distance control devices or locally by hand (the latter only where oil breakers are installed). Moreover, after tripping a transmission line furnished with power sources at both ends, it must be given a trial closure supposedly from one of the ends, if the ARC devices accounting for the double-end supply are not available or are temporarily inoperative. An ARC device used for voltage trial reclosure from one end must be able to check for opposing line voltages.

The variants in the ARC devices may be discerned from the following:

The action on the three phases (TPARC) or one phase (OPARC) of the breaker.

The type of equipment to which the voltage is applied. These are overhead or cable transmission lines, transformers, busbars and electric motors.

The type of switching devices under the effect of the ARC device. These are air- and oil-breakers, contactors or magnetic starters and fuses.

The type of power supply to the equipment whose breakers are under the effect of the ARC device. These are power system elements supplied from one or two ends, included in a loop system or forming a single tie link.

The type of action, as single- and multishot (reclosure) ARC devices. Examples are devices accomplishing two and three reclosures.

The type, mechanical, pneumatic and electrical.

The speed of action, as high-speed ARC devices (HSARC) ensuring no-power intervals of 0.5 s or less and normal speed devices with time control to assure greater no-power intervals.

The method of voltage control across the load being reenergized, as ARC devices responding to voltage or no-voltage.

The method for monitoring the synchronism during automatic reclosing operations, as those which respond to synchronism (ARCSS), asynchronous ARC (AARC), combined with self-synchronization of the generators and synchronous capacitors, those which control synchronism, etc.

Peculiar functions are performed by the ARC devices set into operation after recovery of frequency and voltage. The former (FARC) devices are used for the ARC of breakers tripped by the AFC devices and the latter ones, for the ARC devices of electric motors tripped to ensure self-starting of important loads.

When selecting the type and circuit of an ARC device, one must consider the circuit diagram of the power system and power supply to the consumers. An example illustrates this.

Assume that a part of the power system shown in Fig. 8-1 need to be equipped with ARC devices.

Transmission lines *1-2-3* are single feeders with one-end supply. To recover the power supply to the loads of substations *2* and *3*, use may be made either of three-phase ARC devices or devices for phase by phase automatic reclosure (the latter devices being employed if there is a dead-earthed neutral point).

Transmission line *4-5* connects two parts of the power system incorporating generation sources. There are no other parallel links between these parts of the system, as line *8-3* is normally open. When implementing ARC devices on line *4-5*, consideration should be given to the variants of asynchronous connection of power system parts (AARC) linked by the given transmission line and the

installation of OPARC devices or ARC devices with synchronism seizing, or ARC devices for line voltage trial at one end.

When choosing ARC devices for lines *4-14* and *5-13* one should also consider the possible use, in addition to the above-mentioned ARC devices, of an ARC

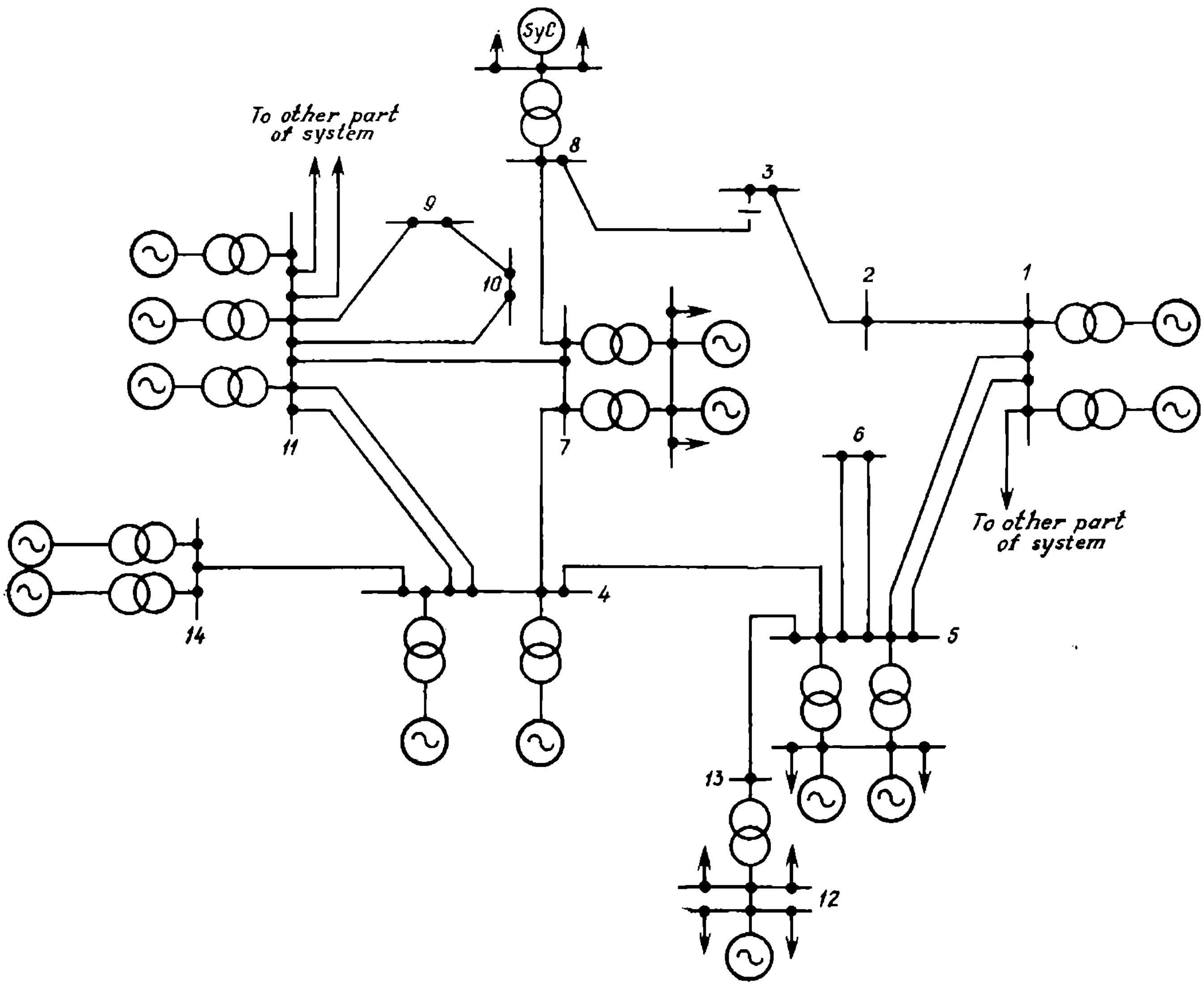


Fig. 8-1. A section of power system

device for a sectionalized load area with preliminary disconnection of local station generators from the power system together with some loads of this area. With a successful performance of the ARC devices on lines *5-13* and *4-14* from the power system side, it is advisable to furnish the switch, used for pulling the sectionalized load area in step with the power system, with an ARC device capable of synchronism seizure in order to automatically reestablish the normal configuration of the circuits. In a number of cases proper operation of the synchronism seizing ARC device takes place after the action of the AFC device in the sectionalized area and after the frequency in this area is recovered to a value close to the power system frequency.

Consider the operation of the ARC device on line *7-8*. Substation *8* may be placed under voltage from the side of substation *7* after the synchronous capacitor (or the synchronous motors of the loads) is deenergized. After recovery of the busbar voltage of substation *8*, the excitation should be automatically reapplied and the synchronous capacitor (the synchronous motors) will restore the synchronous operation.

Loop circuit *11-9-10* has one point of supply, from substation *11*. When installing ARC devices in this type of circuit no problems arise as to the possibility of asynchronous connections.

System section *4-7-11* has three points of supply, one from substation *7*, one from substation *11* and one from substation *4*. Under certain conditions, reclosure of one of the lines of this section may be asynchronous. Whether such a reclosure is permissible and useful should be ascertained when selecting the ARC circuit.

Lines *5-1* are parallel. The use of another line allows the paralleled sections of the power system to be easily controlled by means of the current in the other operating line. When selecting an ARC circuit for lines *5-1*, this factor should be taken into consideration.

In practice, various ARC devices may be applied. The choice of the best variant is made in the engineering design, preference should be given to devices which mostly assure trouble-free operation, simplicity in design and service. Operation of the ARC devices must be coordinated with the performance of the protective relaying devices installed on the equipment. In particular, if a substation is provided with differential protection means for the busbars, consideration should be given to the problem of using the busbars of ARC devices with their preliminary testing with voltage from any of the transmission lines with the subsequent automatic recovery of the circuit configuration if the busbars are in sound working order.

The operating time of ARC devices (t_{ARC}) is the time from the instant the ARC device is started to the time when the reclosure pulse is given. This time should be sufficient for the breaker to be ready for reclosure after the short circuit is cleared with subsequent isolation of the short circuit if the reclosure fails.

The operating time of an ARC device should not be confused with the ARC time which includes the operating time of the ARC device and the time taken by the breaker from the instant it receives the control signal to close to the touch of the current-carrying contacts. The automatic reclosure time is naturally less when use is made of high-speed breakers.

The no-power interval (*dead-time*) is the time from the instant the breaker arc extinguishes when tripping the circuit under control to the instant this circuit is restored after operation of the ARC device and closure of the breaker.

Experiments have shown that a minimum no-power time sufficient for the deionization in the arc space on overhead lines (at no-voltage) is from 0.15 to 0.2 s for 110-kW lines and from 0.35 to 0.4 s for 500-kW lines. For the lines rated for other voltages, the deionization time may be determined by extrapolation. At the above-mentioned no-power time ratings, effective actions of the ARC

system may be expected in more than 50 per cent of the cases. With no-power time increase, conditions for deionization in the arc space improve and the percentage of effective operations of the ARC devices rises.

The above no-power minimum intervals are obtainable only with high-speed automatic reclosures for which specially adapted air breakers are used.

With ordinary type breakers rated for 3 kW and more, not intended for HSARC operations, the minimum ARC device functioning time lies within 0.3 to 0.5 s. The closure time of the breakers themselves is 0.5 to 1.2 s. Thus, if a transmission line is supplied from one end tripped by a breaker equipped with an ARC device, the total no-power time of the line far exceeds the no-power interval required for deionization in the arc space.

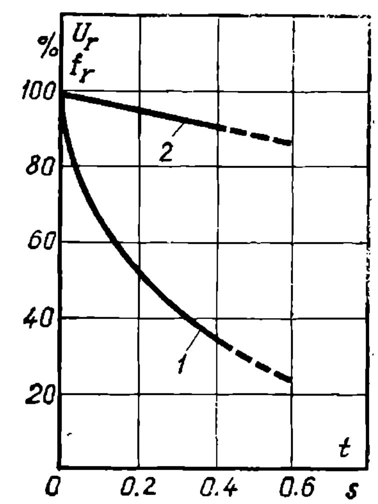


Fig. 8-2. Voltage (*1*) and frequency (*2*) versus time on substation busbars after tripping supply line (experimental data)

When the ARC devices were placed into service it was feared that, after tripping the line at the supply end, the arc in the faulted place would be sustained due to the energy stored by the revolving (under inertia) asynchronous and synchronous motors at the receiving end of the line.

Experience has shown that the effect of the asynchronous load may be neglected from the point of view of persisting arc with operating time of ARC devices ranging from 0.3 to 0.5 s and with the ordinary type breakers.

Figure 8-2 shows the busbar voltage and frequency variations against time at a substation being disconnected. The load connected to the substation busbars included: asynchronous motors, lighting circuits, and capacitor banks (load power $P = 4.7$ MW; $I_{as.m} = 440$ A: $I_{light} = 60$ A; $Q_c = 2$ Mvar; and the rated voltage 6.3 kV).

It is evident from Fig. 8-2 that in about 0.6 s the busbar voltage decreased to 20 per cent of the rated value.

If the receiving substation is equipped with synchronous capacitors (motors), the voltage falls at a slower rate. In this case, the ARC device operating time at the feeding end of the line should be sufficient to allow the synchronous capacitors (motors) to be tripped or unexcited before the line is reenergized, otherwise they may be asynchronously connected which is dangerous because of arising mechanical efforts. Furthermore, connection to an unextinguished arc sustained by the excited synchronous capacitors (motors) revolving due to inertia may happen.

When deciding on the number of reclosures to be performed by the ARC devices, it should be remembered that a one-shot automatic reclosure is the one most simply accomplished both as to the ARC device itself and to the readiness to reclose the breakers.

More complicated are two-shot automatic reclosures and even more complicated are three-shot automatic reclosures.

In addition to this, as is shown in service, the efficiency of each subsequent ARC cycle abruptly falls with each repeated reclosure.

Thus, according to the USSR statistics the ARC operations on lines are 60 to 75 per cent effective in the first cycle, 10 to 15 per cent in the second, and only 1.5 to 3 per cent in the third.

The USSR State Standard specifies the operating conditions of breakers for them to suitably operate with an ARC device designed to serve a certain number of subsequent reclosures.

Symbols are used to denote the breaker tripping and closing operations. The letter $\dot{O}$ indicates an opening (tripping) operation and the letter C, a closing operation. For instance, if a breaker is open and then in the interval $t_{interv1}$ it is closed by an ARC device and again opens, i.e., operation of the ARC device is ineffective, the process is described as follows: $O—t_{interv1}—CO$. The symbolic notification $O—t_{interv1}—CO—t_{interv2}—C$ means that the breaker was tripped, then in time $t_{interv1}$ the ARC device reclosed it, next, it opened again and was repeatedly closed in time $t_{interv2}$ by the ARC device and as the next step, it remained closed (an effective two-shot automatic reclosure took place). The operation of a breaker with a three-shot automatic reclosure is written down in a similar manner.

When using ARC devices for air breakers a sufficient supply of compressed air should be provided to ensure operation of the breaker in compliance with the specified number of reclosures by the ARC device. Here also considerations should be given to the possibility of the breaker closing with a continuous short circuit. The time intervals at which the breaker is closed from a two- or three-shot ARC device should be such that the oil breakers have enough time to restore their tripping ability and the air breakers can restore their pressure in the compressed-air mains.

The first pulse to reclose a tripped breaker is given by the ARC device in 0.3 to 2 s, the time for the second reclosure is 10 to 15 s. The time for the third reclosure carried out by a three-shot ARC device can be from 1 to 5 min.

Operation characteristics of ARC devices are given in Table 8-1[8-2].

The ARC devices are started by the protective relaying system, or when the control key and the breaker are in different positions, or at any time when the breaker trips. In the last case, provision should be made to prohibit the operation of the ARC device when the breaker is tripped by attending personnel (remotely or by means of remote-control devices) and also after protective relaying operations permitting no reclosures. For example after operation of the differential protection of busbars or transformers.

When the ARC devices are started from the protective relaying system, their reliable operation must be assured during short-time operation of the protection system and rapid clearing of the short circuit by the breaker.

Two types of ARC devices are used in the USSR.

The single-shot performance of the circuits of the first type is obtained by the use of a sliding contact of a time relay. The other type uses the discharge of a capacitor for the purpose. Each of these variants has advantages and limitations. In the ARC devices which include a sliding contact time relay, mal-

functions are more likely as the contact may jam. In ARC devices with discharge capacitors, the capacitors are liable to puncture and the entire ARC device can misoperate.

The ARC devices which include sliding contact time relays can be made by the power station personnel from standard factory-made relays.

The capacitor type ARC devices are obtained from the manufacturer as complete units.

The breaker closing devices using the stored energy of a raised weight or that of a compressed (expanded) spring assure automatic mechanical reclosures. Such devices were used in 3 to 35-kW power installations. They need no relaying apparatus or sources of operating current. The main disadvantage of the mechanical ARC devices is that their reclosure time cannot be adjusted thus

Table 8-1

Data from a Five-Year Operation of ARC Devices on Overhead Lines

Type of ARC devices	Operation parameters	Operation voltages, kV				
		2-10	20-35	110-154	220-330	400-500
Three-phase single-shot	Number of set-years (K*)	65,131	28,623	19,745	2,626	183
	Effective operation, %	53.5	69.5	75.0	76.5	67.0
	Periodicity, year:					
	effective	0.65	1.24	0.77	0.82	1.02
	ineffective	0.74	2.86	2.28	2.65	2.08
Three-phase multi-shot	Number of set-years (K)	937	3,085	1,453	82	—
	Effective operation, %	56.2	78.1	80.5	77.2	—
	Periodicity, year:					
	effective	0.25	0.87	0.43	0.34	—
	ineffective	0.34	3.10	1.75	1.17	—
Phase-by-phase acting	Number of set-years (K)	—	—	79	344	132
	Effective operation, %	—	—	73.2	80.7	59.5
	Periodicity, year:					
	effective	—	—	0.43	1.28	1.32
	ineffective	—	—	1.16	5.6	1.94
All types	Number of set-years (K)	66,068	31,708	21,277	3,052	315
	Effective operation, %	53.6	70.5	75.5	77.0	64.5
	Periodicity, year:					
	effective	0.63	1.19	0.72	0.82	1.17
	ineffective	0.73	2.85	2.23	2.70	2.13

* K denotes the number of the ARC devices (sets) times the number of years in use.

causing a relative low percentage of effective operations (due to a too rapid action in the first cycle). Their other limitation is the complex interaction adjustment of the actuating components. Because of this, breakers with spring- or weight-type actuators are nowadays furnished with electrical ARC devices which release the appropriate latch of the trigger closing device.

The operation characteristics of all types of ARC devices for a 5 year period, from 1962 to 1966 is given by the following: the number of set-year units of ARC devices included into the statistics $K = 192{,}022$; effective operation percentage 58.4; ineffective operation percentage 41.2; failure percentage 0.4; periodicity of effective operation, years, 1.04; and periodicity of ineffective operation, years, 1.48.

The data on the operation of the ARC devices of various types are given in Tables 8-1 and 8-2[8-2].

Table 8-2

Service Operation of ARC Devices Installed on Different Equipment over Five Years

Type of ARC	Operation parameters	Work devices				
		combined lines	cable lines	busbars	trans-formers	other equip-ment
Three-phase single-shot	Number of set-years (K)	15,288	22,843	7,258	15,823	7,631
	Effective operation, %	56.2	45.3	64.8	60.0	64.4
	Periodicity, year:					
	effective	1.3	4.13	15.5	15.5	8.25
	ineffective	1.69	3.38	28.7	23.0	23.8
Three-phase multi-shot acting	Number of set-years (K)	225	471	—	6	57
	Effective operation, %	68.3	43.0	—	—	—
	Periodicity, year:					
	effective	1.3	11.8	—	—	—
	ineffective	2.8	8.9	—	—	—
All types	Number of set-years (K)	15,513	23,314	7,258	15,829	7,688
	Effective operation, %	57.0	45.0	64.8	60.0	69.8
	Periodicity, year:					
	effective	1.3	4.18	15.5	15.3	8.2
	ineffective	1.71	3.42	28.5	22.8	19.0

8-2. Single Lines with Supply from One End

For overhead and cable power transmission lines supplying loads from one end, the use of ARC devices is compulsory.

The reasons for the use of ARC devices on overhead transmission lines are obvious and explained above. The ARC devices installed on the breakers of cable lines have a smaller effective operation percentage, however their usefulness is evident (see Table 8-2).

Effective operation of the ARC devices installed on the breakers of cable lines is accounted for by the fact that the breakers trip not only because of a

cable short circuit (which, as a rule, persists after deenergizing the line or, if not so, then the short circuit is eliminated as the cable core burns), but also due to short circuits at the cable connection busbars, pothead terminals, or when the entrance connections are damaged by fuse flashes. In cases like these

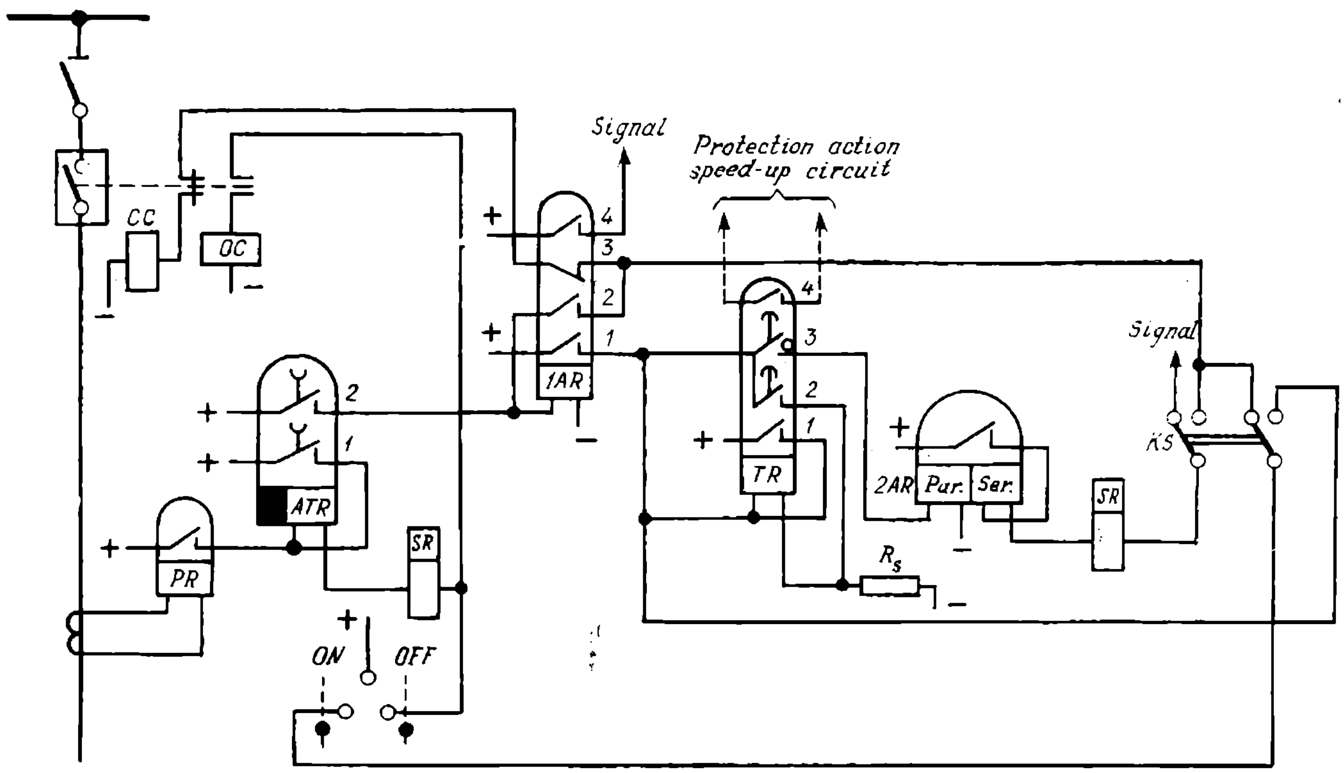


Fig. 8-3. Three-phase single-shot ARC device started by protective relaying

the cause of the cable tripping often disappears after deenergizing. Cable lines operating at 3-6-10 kV are not infrequently tripped due to overload current which disappears when the loads are deenergized.

The action of electrical ARC devices installed on the lines supplied from one end is now considered.

Three-phase one-shot ARC device started by the protective relaying. The coil of relay *ATR* is connected in series with the contact of protection output relay *PR* (Fig. 8-3) and placed into the tripping coil circuit of the breaker.

After the protection output relay has functioned, its coil becomes energized and attracts the armature. Closing contact *1* of the relay *ATR* closes the self-holding circuit which holds until the opening of the blocking contacts, found in the breaker coil disconnecting circuit, after it has tripped. The necessity for the self-holding was found in service as it was noticed that where no self-holding circuit is used the armature drop-out time of relay ATR was often insufficient to trigger the ARC device (to close contact *1AR-1*, make the relay *TR* function and close its contact *1*). This can happen, when the short-circuit circuit is too quickly tripped by the breaker with a resulting trip of relay *PR*.

The contact *ATR-2* closes the auxiliary relay *1AR* which in its turn makes the coil circuit of time relay *TR*. Sliding contact *3* promotes the pre-assigned operating time of the ARC device, then end contact *2* by its closing releases the circuit.

The relay *1AR* prevents the breaker from multi-shot reclosure in case of a jammed sliding contact of the time relay or baked contact of the output relay of the ARC device. Therefore, the closing circuit is excited through the tripping contacts of relay *1AR*. If connection is made to a short circuit and the closing pulse is not removed the relay *1AR* switches over the tripping circuit to its coil after operation of the protection and remains closed until the closing pulse is removed. The closed position of the relay is indicated.

The time relay *TR* holds itself by the instantaneous contact. Sliding contact *3* completes the circuit of the parallel coil of relay *2AR*. Since the time during which this circuit remains closed is insignificant, provision is made to enable the relay *2AR* to hold itself closed. The relay *6AR* has two coils. The series coil is closed by the relay contacts for the time enough for the breaker to close and its blocking contacts open.

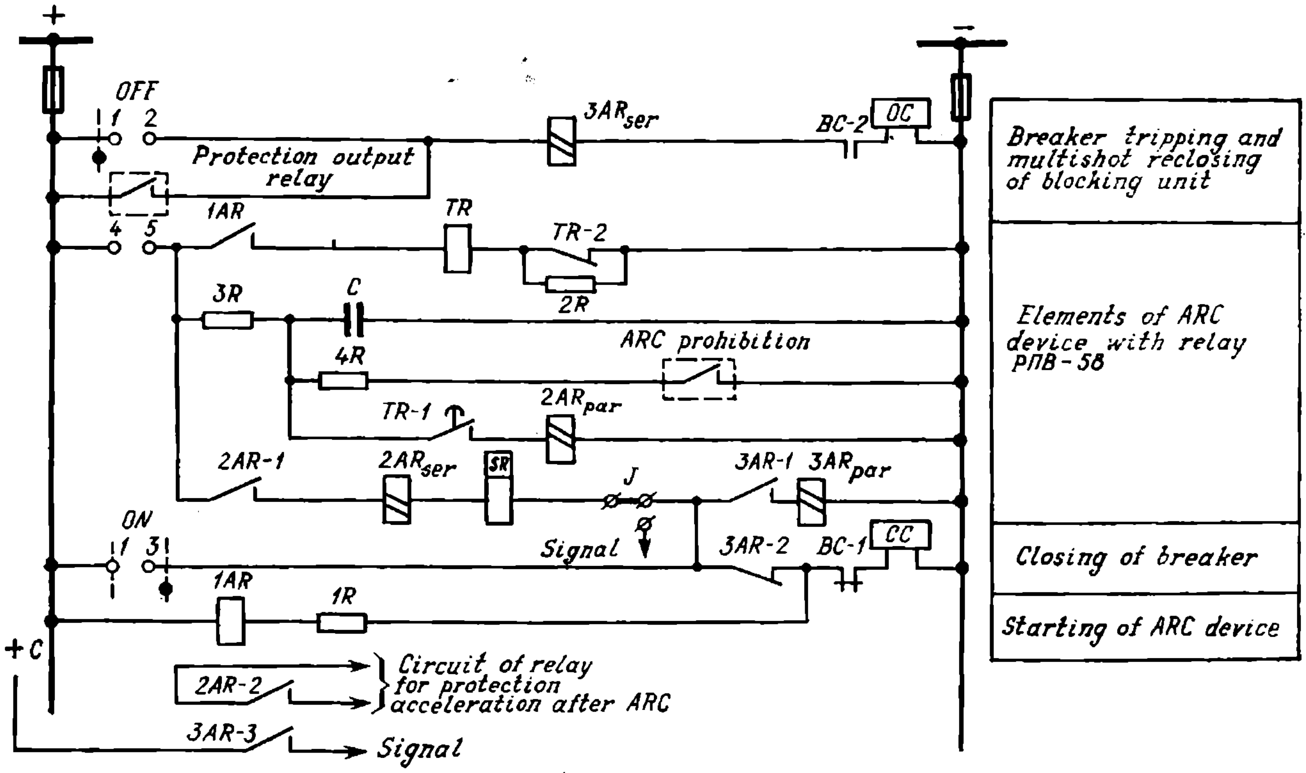
The time delay of the end contact *TR-2* is such that it overlaps the time taken by the breaker to disconnect from the protective relaying circuit when connected to a persisting short circuit. If the time delay of end contact *2* is less, the result will be repeated reclosures of the breaker. The closing time of contact *2* is the sum of the time periods necessary to close sliding contact *3*, reclose the breaker, operate the protection and trip the breaker with a time margin. When provision is made to speed up the operation of the protection, after the functioning of the ARC device, by the time needed to quickly clear a persisting fault, the operating time of the protection is about 0.1 s and the time margin is from 0.7 to 1 s.

The circuit intended for speeding up the action of the protection is shown by the dashed line.

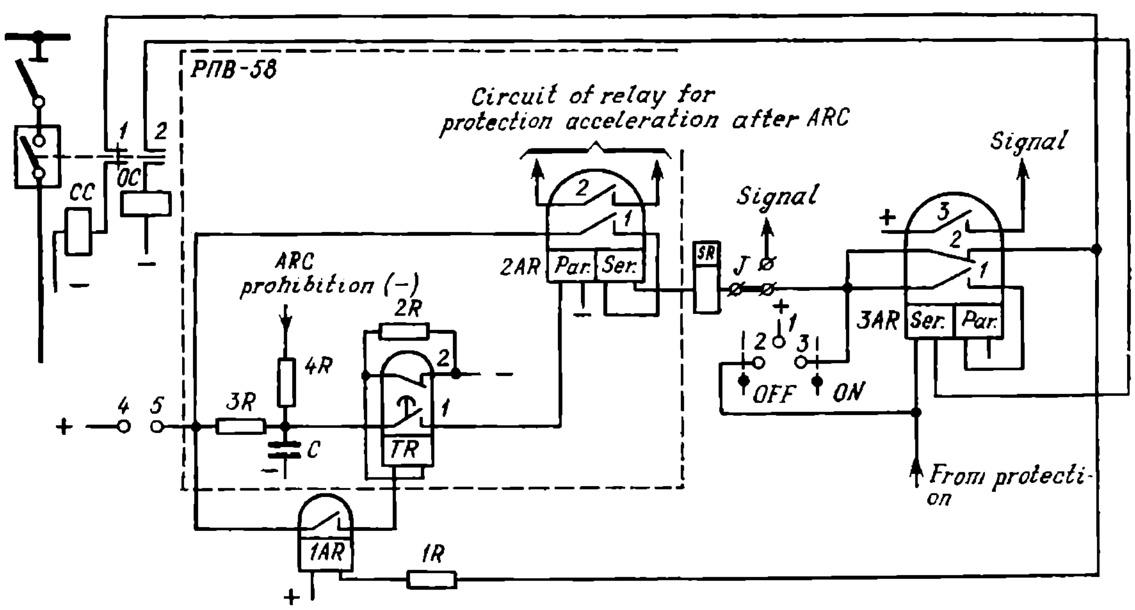
If the breaker is connected locally from the switchboard or from the load-dispatching department by a remote control system then, after tripping, the breaker should not be reclosed as the cause of the tripping is very likely to persist. An example is a manual closure after repair operations because of unconnected earth faults or bad repairs. This requirement is met by closing the breaker manually by feeding a control pulse to the relay *TR* of the ARC device.

With the aid of the knife switch *KS* the ARC device can be removed from the operation with the direct changing over of the closing circuits to the closing coil of the breaker. Provision may be made to remove the ARC device from the operation automatically when the breaker is closed by the control key or a remote-control device. This, however, makes the circuit more complicated and therefore cannot be recommended.

Three-phase one-shot ARC device started when the breaker and the control key are in different positions. When the breaker is tripped by the protective relaying system uncorresponding positions between the breaker and the control key closing circuit *4-5* (Fig. 8-4*a* and *b*) occur. Because of this, the operation of the relay *1AR* is followed by closure of the time relay *TR*. The contact *TR-2* of this



(a)



(b)

Fig. 8-4. One-shot three-phase ARC device, type РПВ-58, started when breaker and control key are in different positions

(a) developed diagram; (b) condensed diagram; circuit 4-5 is closed by contactor stack in position ON and opened in position OFF

relay cuts in the current-limiting resistor *2R* (to ensure the thermal resistance of the coil of relay *TR*), while its contact *TR-1*, having a specified delay, completes the discharging circuit *C* by connecting it to the parallel coil of relay *2AR*. The relay *2AR* functions and is held by the contact *2AR-1* closed through its series coil until the blocking contacts of the breaker open the circuit of this coil after making.

The one-shot operation of the ARC device is caused by capacitor *C* which discharges after the circuit is completed by the contact *TR-1*.

The capacitor can be charged only after the breaker is closed, i.e., when the relay *1AR* is deenergized for a prolonged period and its contact remains open. The charging time of the capacitor is from 16 to 20 s and may be adjusted by varying the resistance of *3R*. When the breaker is tripped capacitor *C* cannot charge, since the charge current leaks from capacitor *C* through the closed contact *TR-1*, the parallel coil of relay *2AR* to the negative terminal of the power source.

After tripping the breaker by the control key, one of its contact assemblies opens circuit *4-5* to remove the operative current from the relay contact *2AR-1*. The charge from the capacitor leaks down through the above-mentioned circuit as the relay *TR* is closed and its contact *TR-1* remains closed, and also through the coil of relay *TR* to the negative terminal of the source of operative current.

Therefore, after the breaker is closed by the control key or the ARC device, operation of the ARC device can be repeated only after charging capacitor *C*. Should it happen that the transmission line is connected to a short circuit, the protective relaying system will perform the tripping operation before the ARC device is ready for action.

To prevent the breaker from repeated reclosures and trippings when the closing signal is applied for a long time and the short circuit persists, the circuit is furnished with a relay *3AR*.

If to some reason, the closing circuit of the breaker remains closed for a long period due to, say, a fused contact of relay *2AR-1*, and the breaker connects to a short circuit, then the protection system will make it trip. It will not be reclosed as at the instant of tripping the series coil of relay *3AR* carries current. The relay *3AR* will function. The contact *3AR-2* opens the closing circuit of the closing solenoid, the contact *3AR-1* closes the parallel coil of relay *3AR* (the relay remains closed until this self-holding circuit is opened) and the contact *3AR-3* makes the signal circuit, thus indicating a trouble in the ARC device or the control key.

The use of relay *3AR* makes it possible to avoid using the unreliable interlocking systems which guard against multifold reclosures (interlocking against "jogging") and are employed in some actuators of the circuit breakers.

The ARC device operating time is controlled by the time setting of the *TR* relay.

The possibility of accelerating the action of protection system is foreseen after (or before) the operation of the ARC device. For this, use may be made of the *AR-2* making (or breaking) contact.

Three-phase one-shot ARC with prohibited operation when breaker is remotely tripped (Fig. 8-5). The circuit is designed so that reclosure of the breaker is

accomplished regardless of the fact whether it is tripped locally or remotely.

To prevent the breaker from reclosure after tripping by the control key or the remote-control device, a pulse "prohibiting" the action of the ARC device is given simultaneously with or somewhat before the closure of the tripping

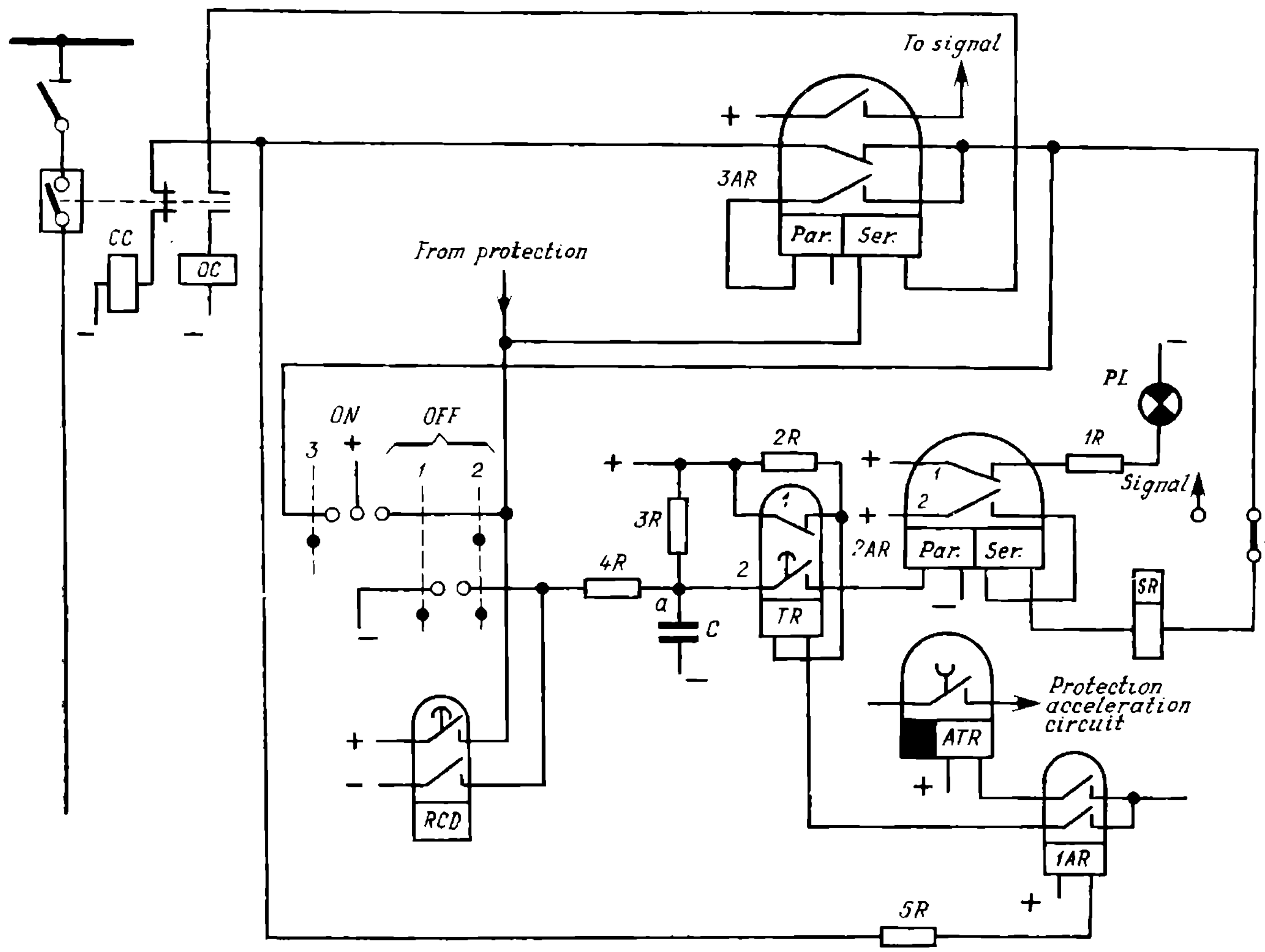


Fig. 8-5. One-shot three-phase ARC device with prohibited operation when breakers are tripped by control contactor or remote-control device without the use of two-position relay

circuit. This is accomplished by connecting the negative terminal of the capacitor bank to the point "*a*" so that the capacitance is discharged. The function of resistor *4R* is to limit the discharging current.

As previously mentioned, further action of the ARC device requires 16 to 20 s. When the breaker is tripped the capacitor charge constantly leaks through the contact *TR-2* and the parallel coil of relay *2AR* to the negative terminal of the bank. This prevents automatic reclosure of the line after it is reconnected to a short circuit by the control key or remote control device and after the breaker is tripped by the protection system.

As in the circuit shown in Fig. 8-4, blocking against repeated reclosures and tripping operations at any trouble, including a burned contact in the relay *2AR*, is performed by relay *3AR*.

Another way to realize an ARC system at remotely controlled substations is by using a two-position relay, type PП-352 (Fig. 8-6) to start the ARC device. A specific feature of this relay is that, when current flows in one of its coils (the first one) the relay armature sets in a certain fixed position and remains

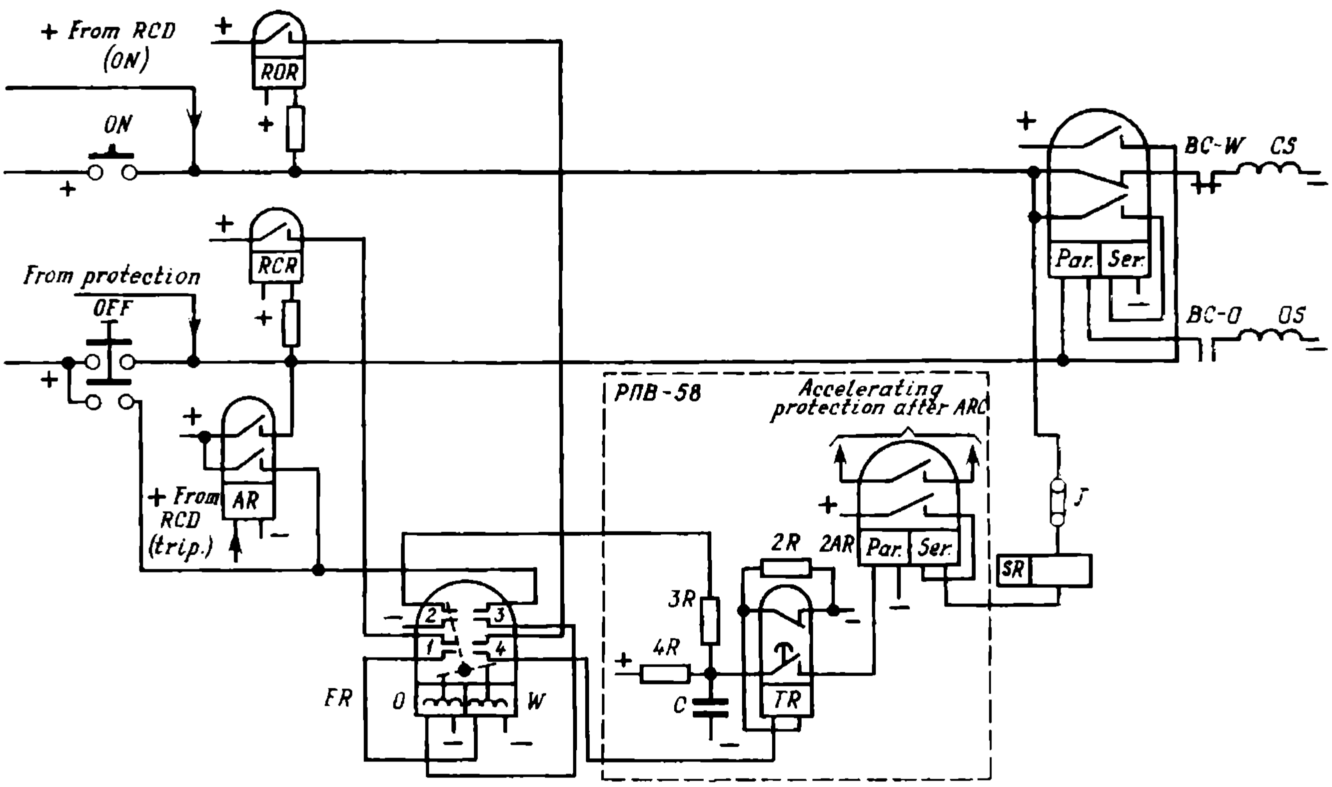


Fig. 8-6. One-shot TPARC device with prohibited operation when breakers are tripped by control contactor or remote-control device with the use of two-position relay

in this position after the current flow has ceased in the first coil. The other fixed position is occupied by the armature only when a current flows in the other coil of the relay. With such a relay in the control circuit of the breaker, a control key with an automatic return to the neutral position is used or a push-button with automatic return after the contacts in the ON/OFF circuits have closed. The ARC device operates as follows.

When the breaker is tripped (in the initial position):

The blocking contact *BC-W* of the breaker is closed; thus, the breaker closing circuit is prepared.

The position fixing relay *FR* (type PП-352) is in the position corresponding to the preliminary current flow in the coil *O*, contacts *FR-1* and *FR-2* are closed, and contacts *FR-3* and *FR-4* are open.

The contact *FR-2* completes the operative negative current circuit to discharge capacitor *C* of the ARC device.

The *FR*-1 contact prepares the circuit of the *W* coil of relay *FR*.

After closing the breaker manually or by the remote-control device (RCD) the *RCR* relay operates as its circuit is closed by the *BC-O* blocking contact of the breaker. The coil *W* of the relay *FR* is closed. The position of the armature of relay *FR* changes, i.e., the contacts *FR-3* and *FR-4* close and the contacts *FR-1* and *FR-2* open.

The *BC-W* blocking contact opens and the *ROR* relay becomes deenergized. The capacitor *C* starts to charge. The charging time (as mentioned) is 16 to 20 s.

When tripping the breaker manually or by the remote-control device (RCD) the circuit of coil *O* of relay *FR* becomes connected (through the contact *FR-3*) simultaneously with supplying a tripping signal to the breaker coil *OS*. The relay *FR* is set to the position corresponding to the tripped position of the breaker. The contact *FR-4* opens and the operative current is removed from the time relay *TR* of the ARC device after the relay *ROR* has picked up (after closure of the blocking contact *BC-W* of the breaker) and no reclosure occurs.

When tripping the breaker from the protection system or if tripping is spontaneous the fixing relay *FR* and the breaker will be in different positions. The *FR* relay obtains the position in which its contacts *FR-3* and *FR-4* are closed. After the breaker has tripped and the relay *ROR* operated, the time relay *TR* of the ARC device closes through the circuit completed by the contact *FR-4*. The time relay picks up after the specified time has elapsed. The capacitor *C* will discharge into the coil $2AR_{par}$. The relay *2AR* will operate and reclose the breaker.

If the short circuit on the line persists, the line will be tripped. No reclosure from the ARC will take place as the capacitor *C* has discharged and the charge leaks off through the closed contact of the relay *TR* and the coil $2AR_{par}$.

The relay *FR* resets after attending personnel have set it to the position in which the contacts *FR-1* and *FR-2* are closed while the contacts *FR-3* and *FR-4* are opened.

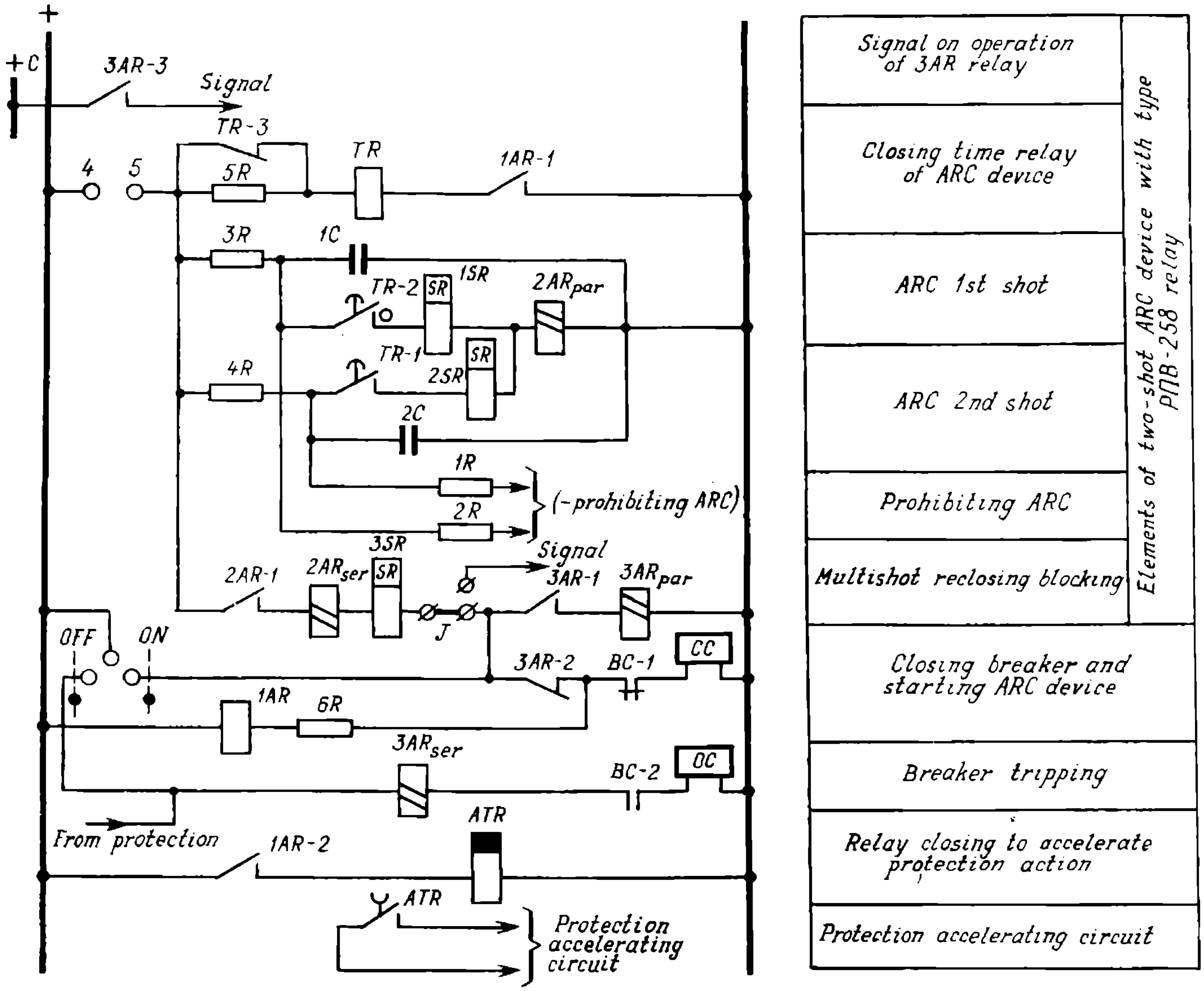
After the breaker is closed manually at a short circuit no automatic reclosure takes place, as the capacitor *C* is not yet charged. The short circuit will be cleared during the capacitor charging time and the relay *ROR* will remove the operative current from the time relay of the ARC device.

Multi-shot ARC devices. Since 1955, two-shot ARC devices are widely used in the USSR. Three-shot ARC devices are not widely applied as their use means the installation of more complex equipment as compared to the single- and two-shot ARC devices (a motor-type multistage time relay is required). They may be used if the breakers are suitable for operation with three-shot ARC devices.

In the USA power systems three-shot ARC devices are used with the operating time of 2 s for the first cycle, 15 s for the second cycle and 60 s for the third cycle. For the USSR power system the time of the third cycle is 5 minutes.

The two-shot ARC devices can be made by using two sets of one-shot ARC devices with different operating times or a purposely designed circuit (Fig. 8-7).

This device employs the same elements as the circuit of the one-shot ARC unit (Fig. 8-4). The circuit of the mismatch position, which determines whether a reclosure is feasible, is formed when the breaker automatically trips, when the relay *1AR* functions and circuit *4-5* of the control contactor remains closed (i.e., when the position of the control contactor corresponds to the closed position of the breaker). The time relay *TR* functions. The contact *TR-3* opens and places the resistor *5R* into the circuit to ensure the thermal stability of the coil of relay *TR*. Some time later, a period which determines the operating time of the first reclosure, the sliding contact *TR-2* completes the discharging circuit of the capacitor *1C* through the coil of signal relay *1SR*, the parallel coil of relay *2AR* and on to the negative terminal of the power source.



(a)

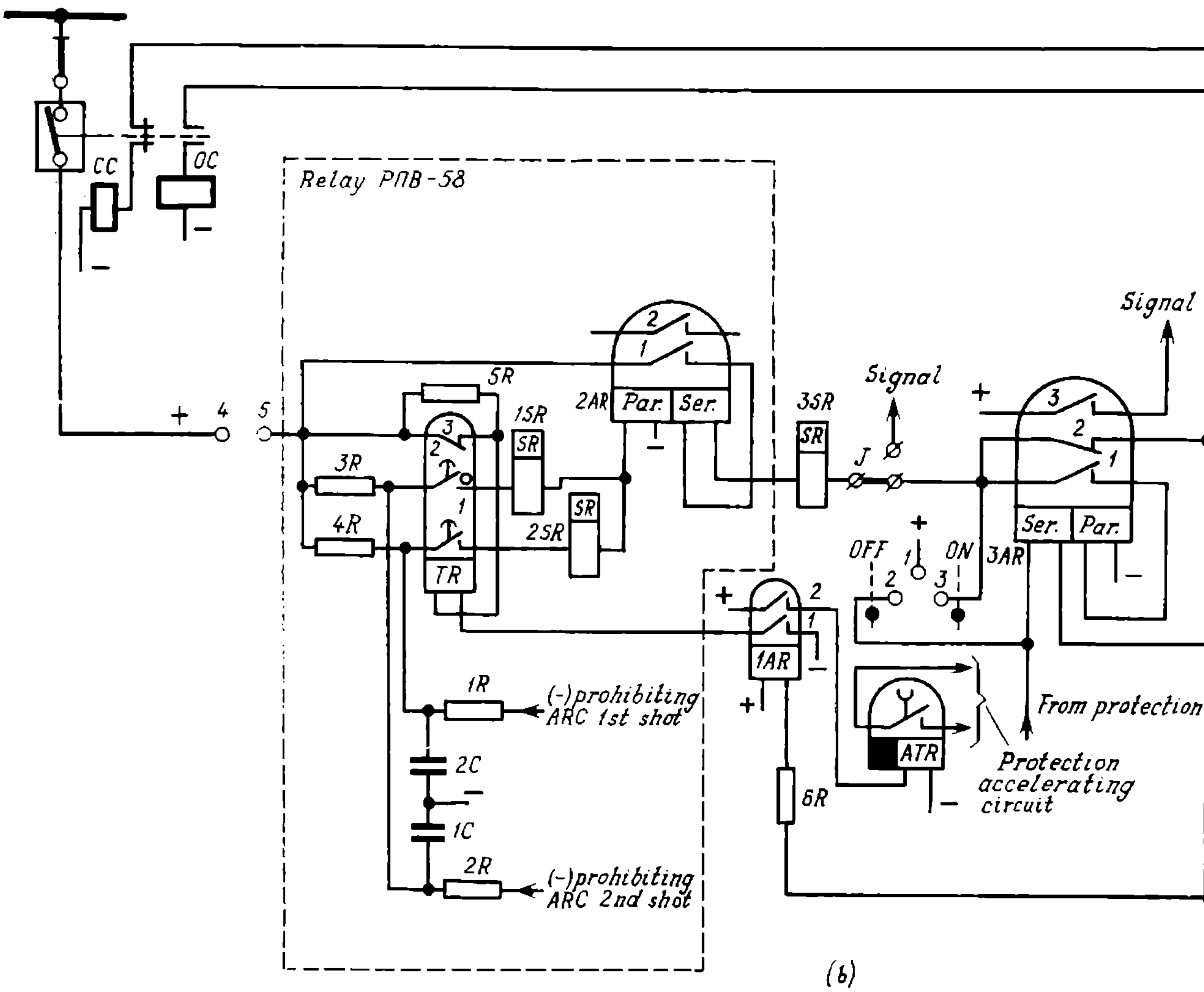
Fig. 8-7. Two-shot three-phase

(a) developed diagram; (b) condensed diagram; circuit 4-5 is closed

The relay *2AR* functions, holds itself by the series coil and feeds a closing signal to the breaker via the coil of signal relay *3SR*, jumper (bridge) *J* and contact *3AR-2*.

If the automatic reclosure is effective, the breaker remains closed. The relay *1AR* becomes deenergized, the relay *TR* resets and the capacitor *1C* starts to charge through the circuit formed by the positive terminal of the power source, closed contacts *4-5*, resistor *3R* and the negative terminal of the power source.

If the automatic reclosure is ineffective, the breaker trips again and the relay *1AR* functions once more. The time relay *TR* again starts time counting and closes the contact *TR-2*. In this case, the relay *2AR* does not function, as the capacitor *1C* is not yet charged (the charging time is 20 s). The end contact *TR-1* closes (its setting being 10 to 15 s) and another closing signal is fed to the breaker, as the capacitor *2C* has discharged through the coil of signal relay *2SR* and the parallel coil of relay *2AR* to the negative terminal of the power source. The relay *2AR* functions and feeds a signal to close the breaker.



(b)

ARC device, type РПВ-258

...by contactor stack in position ON and opened in position OFF

If the second automatic reclosure is ineffective, the breaker is again tripped by the protection system. The relays *1AR* and *TR* repeat their operation. However, no closing signal will be fed as the capacitors *1C* and *2C* are discharged.

With the breaker tripped and the relay *1AR* closed, the capacitors *1C* and *2C* cannot be charged, as their charges leak off to the negative terminal of the power source through the coils of the relays.

A circuit is provided in the device to prohibit the first and second reclosures by discharging the capacitors *1C* and *2C* through connecting them to the negative terminal of the power source via a circuit which includes resistors *1R* and *2R*.

The protection is speeded up each time the ARC device operates, either through the use of the contact *2AR-2* or with the aid of an auxiliary contact of the relay *1AR* which controls the circuit of the relay *ATR*.

The relay *3AR* guards against repeated reclosures of the breaker in case the closing signal is continuously applied (an example may be a trouble in the ARC device) or if a short circuit on the transmission line persists. After the action of the protection system or after the tripping signal is given, the contactor breaks the closing circuit at the *3AR-2* contacts. If at the same time a closing signal is given, the relay *3AR* holds itself by the contact *3AR-1* closing the parallel coil. Simultaneously a signal is given.

Jumper (bridge) *J* makes it possible to disconnect the ARC device and change over its action to signal.

Mechanical two-shot automatic reclosures turn out to be less effective because it is impossible to obtain a controllable time (not too small) for the first automatic reclosure. Therefore, mechanical ARC devices are replaced with electrical ones which allow for the required reclosure time. The mechanical ARC performance can generally be improved through the use of mechanical ARC devices of two-shot action.

In this case, when the first automatic reclosure (whose operating time is not adjustable) is ineffective, an electric motor is automatically turned on which, 6 to 10 s after the second tripping operation of the breaker, resets the reclosure mechanism (a weight is lifted or a spring loaded) through a reducing gear and the trip mechanism operates. After the second reclosure of the breaker, the circuit of the motor driving the reducing gear is automatically disconnected.

The complex design of mechanical ARC devices dictates their replacement with electrical ARC devices.

8-3. Single Tie Lines Between Power Stations and Substations with Synchronous Loads

When parallel operation of power stations or parts of a power system is carried out over single tie lines without parallel links (Fig. 8-8) disconnection of a line section disturbs their synchronous operation. This should be taken into account when installing ARC devices on these lines.

We now consider the principles underlying the ARC devices which may be used under the given conditions.

ARC for a *sectionalized region.* Under normal operating conditions the regional load is divided into two parts so that if breaker *5* trips (Fig. 8-8) one part continues to receive supply from the power system and the other part is supplied from a local power station. The generation output of the power station is balanced to suit the load. When breaker *5* is closed the local power station operates in parallel with the power system.

When section AB of the tie line is at fault, the load of substation B cannot be continuously supplied from the power station since this causes overloads on

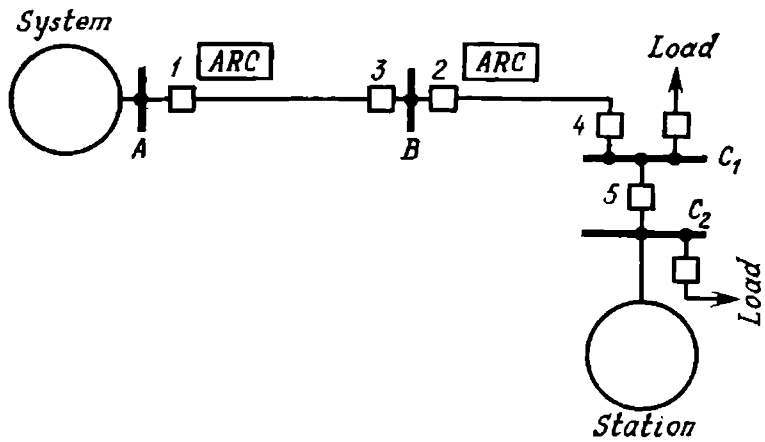


Fig. 8-8. Example of a circuit diagram

the station generators and reduces the frequency and voltage in the region remaining connected to the power station. If no measures are taken to unload the generators the result may be tripped generators and lost supply to the station auxiliaries.

To prevent this, breaker *5* is furnished with a protection which will trip it when a short circuit on sections AB, BC_1 and busbars C_1 occurs. Sometimes the busbar switch of the power station or substation is used as breaker *5*.

Usually for this directional real power protection is applied whose action is controlled by an underfrequency relay. This type of protection trips breaker *5* when the frequency falls and the real power is directed from the busbars C_2 to the busbars C_1.

Similar operations to sectionalize the load are accomplished when section BC_1 is isolated or when a lack of power occurs in the power system with a resulting decrease in the load frequency.

The breakers tripped by the protection devices of sections AB and BC_1 are reclosed by the ARC devices. The ARC device of breakers *1* and *2* is made with a time delay and waiting time for the instant the line is at no voltage, i.e., it waits for the instant when breaker *5* is tripped.

If no-voltage indication is not provided, then to prevent asynchronous connection, breaker *5* is furnished with overcurrent directional protection operating without additional time needed for tripping this breaker at any short circuit on the lines running from busbars C_1 towards the power system, on the power system lines and the lines supplying the loads of the area assigned to the power

system. Here sections AB and BC_1 are regarded as lines supplied at one end, i.e., the loads assigned to the power system will restore their operation after effective automatic reclosure of breakers *1* and *2*, while the protection units and the ARC devices are not installed from the side of breakers *3* and *4* (the breakers also may not be installed). Breakers *1* and *2* are furnished with ARC devices of the same types as those employed by the lines supplied at one end.

Reclosure of breaker *5*, i.e., recovery of the normal circuit is performed manually or automatically if the voltage across busbars C_1 is restored and is in step with the voltage across the busbars C_2.

ARC of supplying line combined with automatic devices removing excitation from synchronous capacitors (motors) when the supply of the substation is stopped.

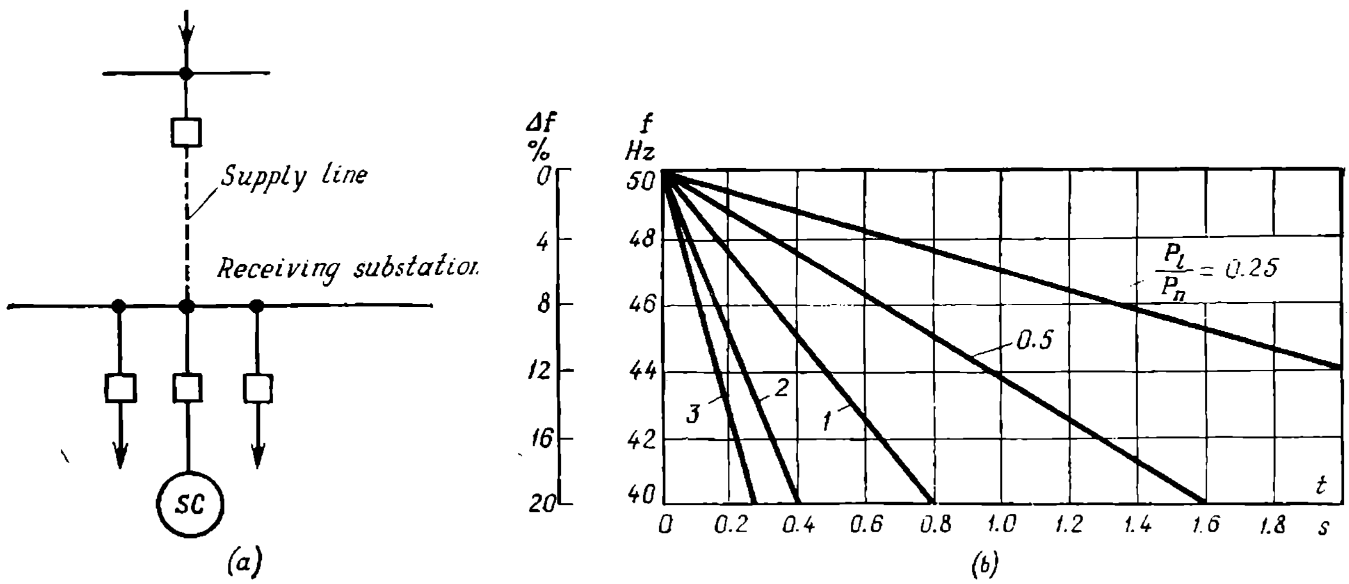


Fig. 8-9. Changes in frequency on terminals of synchronous capacitor after tripping the supply line

(*a*) supply circuit; (*b*) relationship between frequency and time

Fairly often the receiving substation supplied through transmission lines from one side is furnished with a synchronous capacitor to maintain the busbar voltage of the substation at the required level. When the line is tripped at the supply end the synchronous capacitor (Fig. 8-9) or the synchronous motors installed at the receiving substation continue to revolve due to inertia. The result may be a prolonged arc extinguishing process and the excited synchronous machines may be given an asynchronous reclosure. This causes asynchronous connection currents producing severe mechanical torques in the windings and on the shaft. Synchronous motors are usually not designed to operate under such conditions. Many types of motors, for instance low-speed synchronous motors, have starting characteristics at which no resynchronization may be obtained unless the excitation is removed.

Therefore, for effective automatic line reclosure the reclosure time of the breaker from the supply side must be greater than the total time taken by tripping the synchronous load or removing the excitation and extinguishing the

arc. To make automatic reclosure more effective, it must be combined with the operation of the automatic devices which accomplish, after an effective automatic reclosure of the line, reclosing of the synchronous loads (for example, by reclosing the excitation when the hyposynchronous speed is reached).

To accelerate the automatic reclosure of the line, the tripping of the synchronous load or removal of its excitation should be as rapid as practicable.

There are several methods of making automatic devices respond to the tripping of the supply line. It should be noted, however, that the use of an undervoltage relay at the receiving substation does not provide a sufficiently rapid action, as the terminal voltage of the synchronous motors and synchronous capacitors may be sustained long after the removal of supply due to the running of the excited machines under inertia and because of the action of the devices forcing the excitation.

The first method. The tripping of the supply line is detected by a frequency relay responding to the frequency of the voltage maintained by the synchronous motors or synchronous capacitors (SC).

When the supply is tripped the speed reduction of these mechanisms is given by the expression

$$\Delta\omega_{12} = \frac{d\delta_{12}}{dt} \tag{8-1}$$

where $\Delta\omega_{12}$ = decrease in the angular speed
δ_{12} = relative angle between the emf vectors of the synchronous capacitor (motor) and the system

Within a 10 to 20 per cent speed reduction the rotor of a synchronous machine may be regarded as being uniformly retarded, then

$$\delta_{12} = \frac{1}{2}\frac{P_l}{P_n}\frac{\omega_n}{T_{in}}t^2 \tag{8-2}$$

where P_l = total load remaining connected to the motor (SC), losses included
P_n = nominal power rating of the motor (synchronous capacitor)
T_{in} = inertia constant. With synchronous motors this is the inertia constant of the motor-driven mechanism unit
$\omega_n = 2\pi f_n$ = angular speed before the fault

The changes in the angular speed can be determined from (8-2)

$$\Delta\omega = \frac{d\delta_{12}}{dt} = \frac{P_l}{P_n} = \frac{\omega_n}{T_{in}}t \tag{8-3}$$

or it may be determined as a percentage relative to the angular speed of the normal before-fault operation [also see (5-18)]

$$\Delta\omega\% = \frac{1}{T_{in}}\frac{P_l}{P_n}t\,100 \tag{8-4}$$

with $T_i \approx 4$ s

$$\Delta\omega\% = 25\frac{P_l}{P_n}t \tag{8-5}$$

Figure 8-9*b* shows the changes in the speed with different P_l/P_n ratios. It is seen from the figure that after the tripping of the supply line, the frequency

at the stator terminals very quickly drops to a value less than the settings of the last groups of the automatic frequency control devices (46.5 Hz).

For instance, when the SC carries a load three times its rating, the frequency falls to 44 Hz in 0.16 s and with a load half the SC rating, in 0.98 s. If a synchronous motor carries the rated load and operates in parallel with asynchronous motors having the same load, then the frequency decreases to 46 Hz in about 0.15 s.

Thus, a frequency relay having a setting less than that of the last group of the automatic frequency control device may be used as an indicator of a tripped supply line.

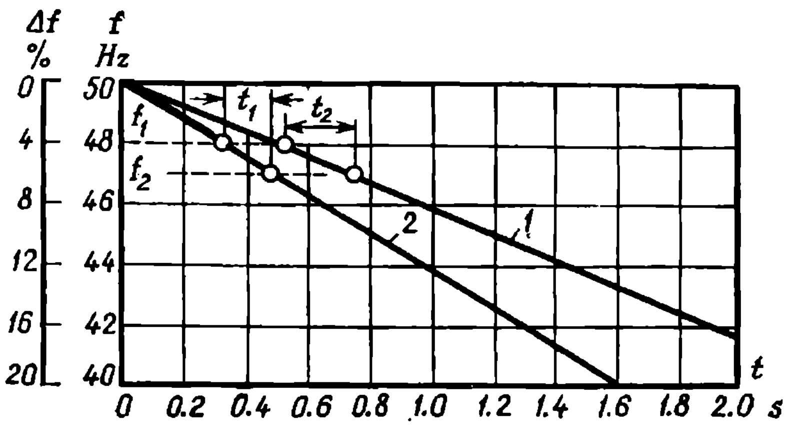


Fig. 8-10. Frequency changes at receiving substation

The second method. The supply line tripping is detected by a device responding to the frequency change rate. Use is made of the difference in the rate of frequency change in the case of power lack in the power system and when a substation furnished with a synchronous capacitor (motor) is deenergized.

Figure 8-10 shows an approximate change characteristic of frequency when 30 per cent of the generation is tripped (line *1*). The characteristic is constructed on the assumption that the power system generators decelerate uniformly during the frequency fall from 50 to 40 Hz due to the effect of a real power deficit after tripping the generation sources. The inertia time constant of the rotating mass of the power system is assumed equal to 15 s.

The fall of the power system frequency is roughly determined from (8-4), assuming that $P_l/P_n = 1.3$

$$\Delta f\% = \frac{100}{15} \cdot 1.3t \approx 8.7t \tag{8-6}$$

When the generation drops by smaller amounts, the frequency varies still less. Fig. 8-10 also gives a change characteristic in the substation frequency when the power supply line is tripped and when a load of about 50 per cent of the SC rating remains connected to the synchronous capacitor (line *2*). As seen from the figure line *2* falls faster than line *1*.

Shown in Fig. 8-11 is the circuit of a device whose operation is based on the above mentioned difference in the rates of frequency changes. Frequency relays *1*

and *2* are adjusted to the operating frequency f_1 and f_2. When the frequency falls below f_1 (48 Hz, for instance), frequency relay *1* functions and closes time relay *3*. If the frequency change rate is small, time relay *3* opens the circuit of auxiliary relay *4* before the contacts of frequency relay *2* are closed (the setting f_2 is less than the operating frequency f_1, 47 Hz, for instance). Relay *4* has no time to close the contacts thus it does not act to trip the FDC unit or the SC.

If the frequency drops quickly, this takes place when the supply line is tripped, relay *2* closes the contact quicker than relay *3* can operate and open

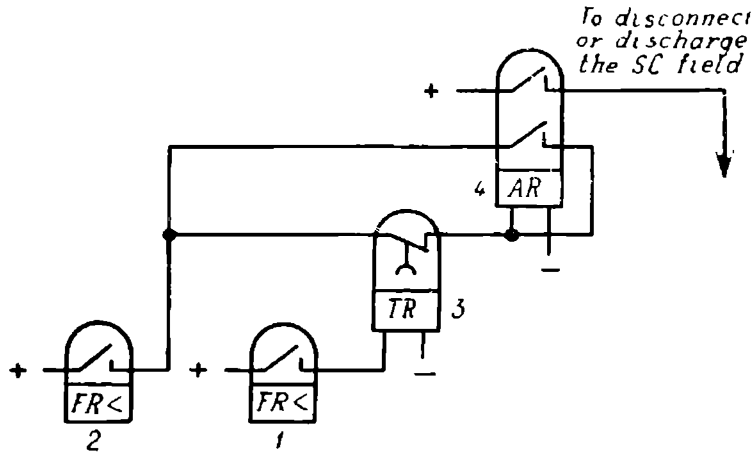


Fig. 8-11. Device responding to frequency change rate

the contact. Relay *4* operates and continues to hold itself after relay *3* has opened the contact with the preset time delay. Relay *4* trips the SC or removes its excitation.

The third method. The tripping of the supply line in this instance is detected by a real power relay connected to the current in the supply line and the voltage across the busbars of the receiving substation. Under normal conditions real power flows to the busbars of the receiving substation. When the transmission line is tripped the power flow towards the busbars of the receiving substation stops and the power relay closes the circuit to trip the synchronous load or discharge the field (directly or through the auxiliary relay). If the synchronous power load is small, as compared with the total load, a current relay may be used in place of the power relay.

Under normal conditions the contacts of the current relay are open due to the effect of the load current. The contacts close when the line is tripped. The reset current of the relay must be greater than the current generated by the synchronous motors when the supply line is at fault.

It is good practice to use the real power (current) relay in conjunction with an underfrequency relay. The supply line tripping is indicated by two factors: no real-power flow which is detected by the power relay, and the frequency fall revealed by the frequency relay. The operation of both relays allows the operating setting of the frequency relay to be 48 to 48.5 Hz, without the risk of its misoperation when the power system frequency falls due to a lack of power which in

its turn speeds up the change of the synchronous load to operation with removed excitation (or the tripping of this load), i.e., makes it possible to speed up the action of the ARC devices from the supply substation side.

The variants of the circuit of a device which automatically removes the excitation of the SC with subsequent reclosure of the field circuit after effective automatic reclosure of the supply line are illustrated in Figs. 8-12 and 8-13.

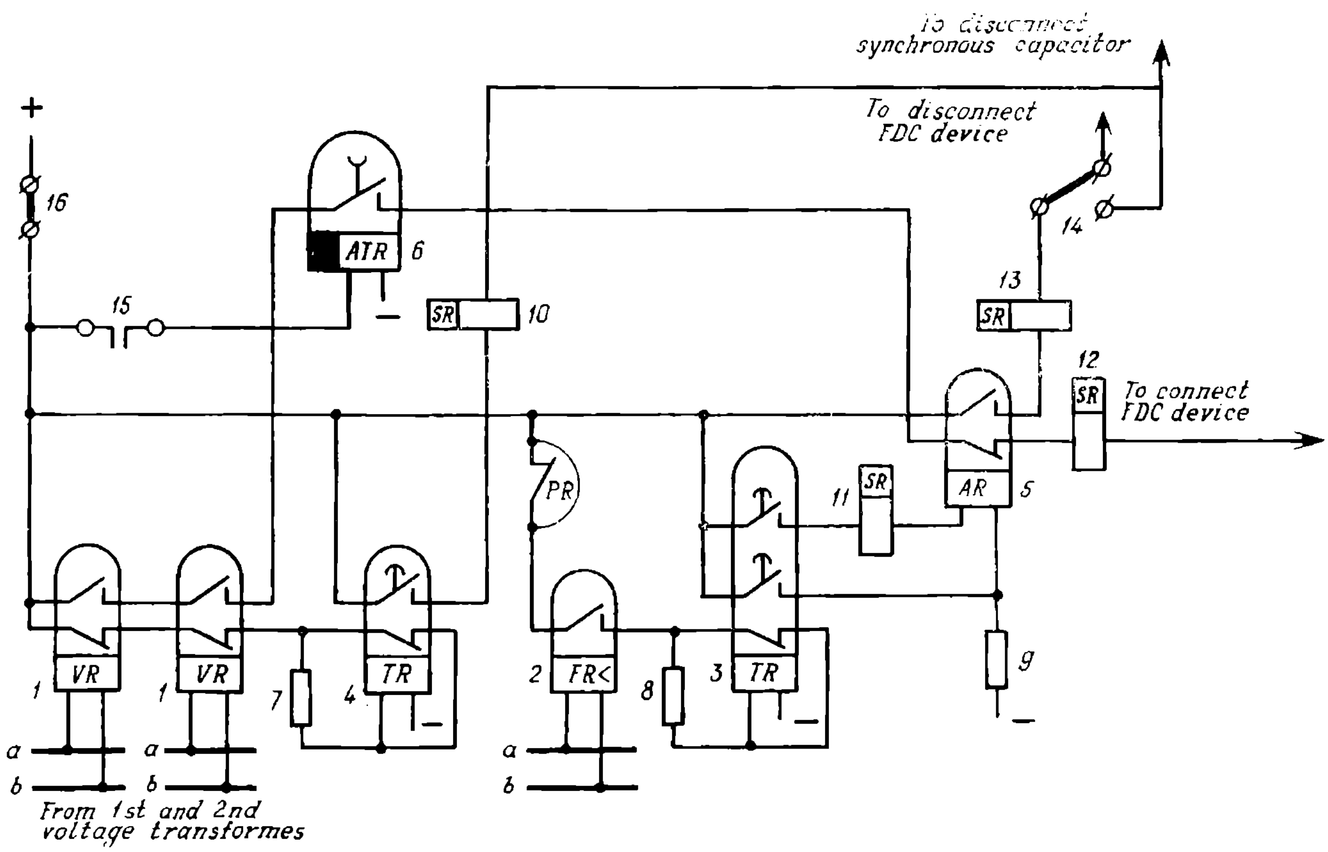


Fig. 8-12. ARC device of synchronous capacitor

1 — voltage relay; *2* — underfrequency relay; *3* and *4* — time relays; *5* — axiliary relay; *6* — relay delayed in reset; *7-9* — series resistors; *10-13* — signalling relays; *14* — switch; *15* — contact on the main breaker (closed when breaker is turned on); *16* — jumper; *PR* — contact of real power relay used in supply line (closed when line is disconnected and no power flow toward receiving station). When relay *PR* is used the circuit shown in broken line is open

The excitation is reapplied either after a specified time (provided the busbar voltage of the receiving substation is restored (Fig. 8-12) or after a speed close to the synchronous speed is reached (monitored by relay *8*, Fig. 8-13).

If the voltage fails to recover within the specified time, i.e., the automatic reclosure of the supply line is ineffective, provision is made to trip the SC. Relay *8* responds to the current in the rotor winding. It is an auxiliary relay with delayed armature dropout. The frequency of the rotor current pulsations with the FDC device tripped corresponds to the slip value. The FDC device is turned on at a slip equal to 5 per cent. Relay *9* ensures the single action of the pulse closing the FDC device.

Asynchronous ARC devices use the same circuit as the ARC devices on the transmission lines supplied at one end. The simplicity and reliable operation of such ARC devices account for their use on lines supplied from both ends.

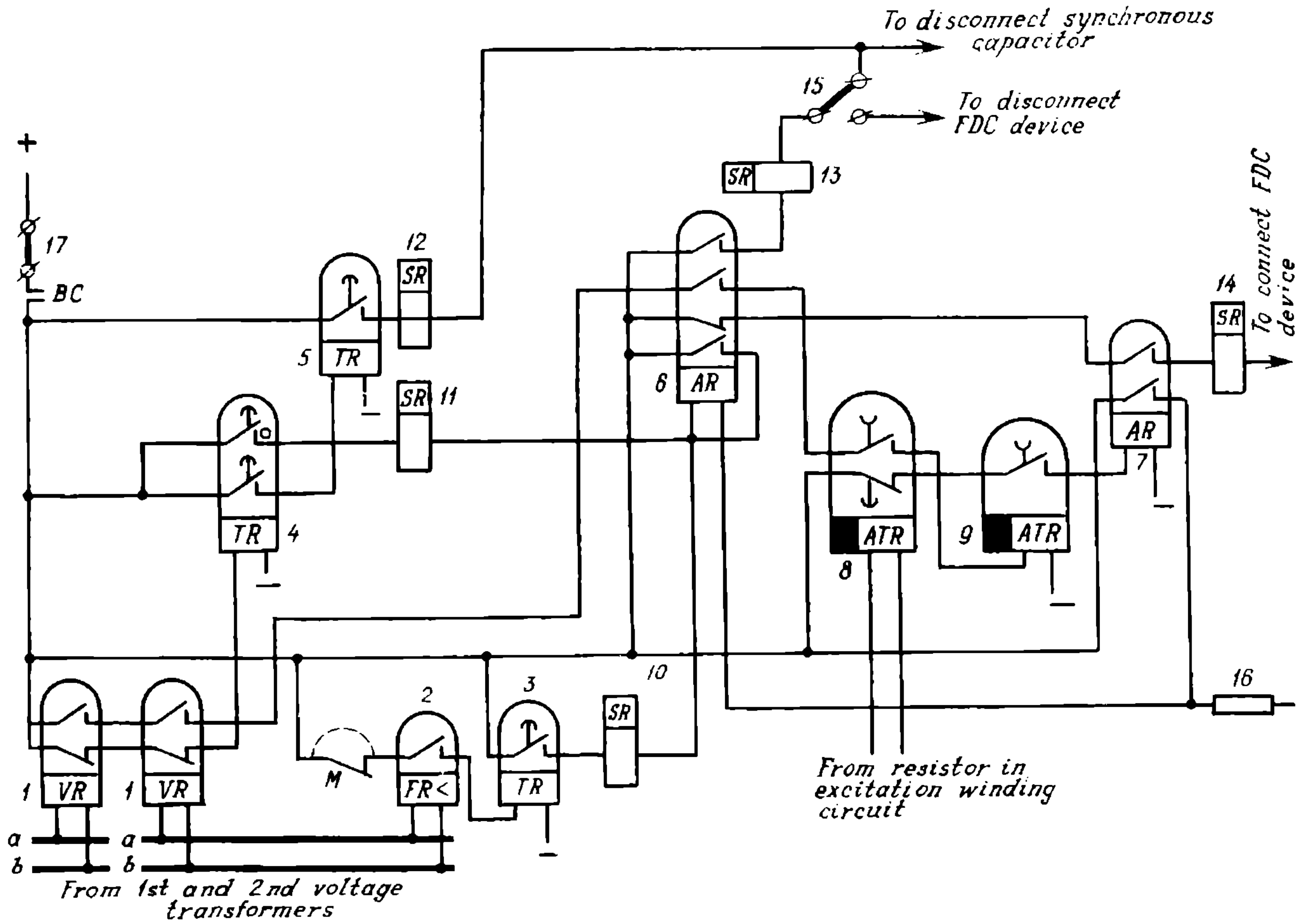


Fig. 8-13. ARC device of synchronous capacitor

1 — voltage relay; 2 — underfrequency relay; 3-5 — time relays (heat resistant); 6-7 — auxiliary relays; 8 and 9 — relays delayed in reset; 10-14 — signalling relays; 15 — switch; 16 — resistor; 17 — jumper; PR — contact of real power relay used in circuit of supply line (closed when line is disconnected and no power flow toward receiving station). When relay PR is used the circuit shown in broken line is open. BC — contact on the main breaker (closed when the breaker is turned on)

The conditions for automatic asynchronous reclosure are the same as those for asynchronous reclosure of the transmission lines. Asynchronous automatic reclosure needs special protective relaying.

The first protection version. The principal protection of tie lines is one which does not respond to currents and voltages during asynchronous operation and synchronous swings. This may be the differential phase high-frequency protection. Protection units responding to zero or reverse components of the electrical magnitudes are used as a back-up protection against asymmetric short circuits. The operating time of these protection units must overlap the possible non-simultaneous phase closures of the breakers and current decays in the protection

circuits. As shown experimentally, the protection operating time should be not less than 0.15 s.

Back-up protections against symmetric short circuits are made with a time delay and respond to total currents and voltages. These protections are furnished with an interlocking device that can close the circuit in the case of asymmetric operation and prohibit operation when the starting element opens the contact; this prevents misoperation when the swing period increases before the power system is pulled in synchronism.

The interlocking circuit is shown in Fig. 8-14. Contact *K* of the starting element which responds to a surge in the magnitudes of backward sequence

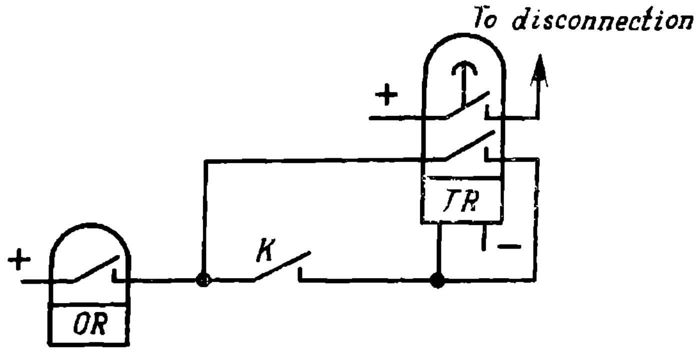


Fig. 8-14. Protection blocking circuit

(the contact of blocking against hunting) closes for a short time the circuit of time relay *TR*.

If a surge arises due to a short circuit occurring in the region under the effect of the ohm relay *OR*, the latter functions and provides holding the relay *TR* and its operation at the specified setting. If a surge occurs during asynchronous reclosure with simultaneous operation of the relay *OR*, the coil of relay *TR* remains closed until the relay contacts open in the first hunting cycle. This done, the coil of relay *TR* cannot close, as its circuit is opened by the contact blocking against hunting. Thus, if the hunting cycle increases before pulling in synchronism, it will have no effect on the operation of the protection system.

In order to prevent the protection from operating directly after an asynchronous reclosure, the characteristic of relay *OR* should be desensitized with respect to the equalizing currents of asynchronous operation and the protection must operate with some delay (0.7 s and more).

The second protection version. To eliminate interphase short circuits, the line is equipped with a distance protection with a stepped time delay and a stepped protection responding to the current and voltage of zero phase sequence in order to eliminate earth faults.

The distance protection against three-phase short circuits has a blocking device that closes the operative circuit only in the case of a surge in the backward-sequence quantities for the time the contacts of the protection starting element remain closed. The circuits of the first zone and the measurement circuits of the second zone open 0.2 to 0.3 s after the surge arises. The time within

which the blocking unit becomes ready for repeated operation must overlap the total time lapsed from the instant the breaker of the line being protected is tripped after the short circuit to its reclosure by the ARC device.

The protection system and the automatic reclosure device operate as follows. When a short circuit occurs, the line is tripped at both ends. The operating time of the ARC device used at one end is set to a smaller value than at the other end, but greater than the tripping time of the breaker used at the opposite end of the line. When the breaker is closed from this end of the line a quick-acting protection is placed into operation for 0.5 s. At this instant the distance protection against three-phase short circuits from both end of the line is rendered inoperative by the blocking unit responding to a surge in the backward-sequence quantities.

If the short circuit persists, the line is instantaneously tripped, if cleared, the line remains completed.

At the other end, the device waits for a voltage. The AARC device is supplemented by a voltage relay to check the line voltage recovery; or, when such a relay is not available, it is made with the time overlapping the tripping time of the line at the opposite end.

By this moment, the accelerating circuits of the protection responding to swing currents are rendered inoperative by the ARC devices. The distance protections against three-phase faults are also rendered inoperative by the swing blocking unit. No line trippings due to equalizing currents take place after AARC.

While after the reclosure at one end the line is under voltage, a fault is hardly probable at the moment the breaker at the opposite end of the line is closed. However, for safety, it is better to use non-selective accelerated protection against asymmetric short circuits with an operating time of 0.15 s at both ends of the line when the ARC device functions. As indicated earlier, this time makes the protection non-responsive to non-simultaneous closures of the breaker phase contacts.

The first stage of the earth fault protection should have the same time if its operating current is not isolated against the maximum currents resulting from asynchronous connections.

The accelerated non-selective protection against asymmetric short circuits is rendered inoperative after the first and second distance protection zones have been returned into operation. Should current and voltage ripple occur after a non-selective reclosure no false tripping occurs with a protection attempted in this way, since the protections responding to swings are automatically rendered inoperative.

It should be noted, that with asynchronous automatic reclosure devices the usual protection systems need no complications, assuming that in some cases, after the ARC devices have operated, the protection system will trip the line if it has no short circuit, thus reducing the total percentage of effective automatic reclosures.

The installation of the AARC devices should be coordinated with the types of the sectionalizing automatic devices used in the power system to stop asyn-

chronous operation. When automatic sectionalizing instantaneous devices are available, the reclosures accomplished by the AARC devices will cause in most cases the sectionalizing devices to operate and divide the power system. Operation of the AARC devices will be effective only on the tie link to the planned point of sectionalization.

When use is made of automatic sectionalizing devices with a swing cycle counter or those which can control the duration of asynchronous operation within a prescribed time, sectionalizing after operation of the AARC devices will take place only if up to the moment of the sectionalizing operation no resynchronization has occurred.

In most cases, when installing AARC devices, it is good practice to use the automatic sectionalizing units with 15 to 30 s time delays; these divide the power system within this time, if for some reason no resynchronization happens.

The purpose of the high-speed ARC devices (HSARC) is to promote reclosures so that the angle between the emf vectors of the sectionalized parts does not reach the δ_{cr} value at which their synchronous operation is disturbed. In fact, high-speed automatic reclosures are accomplished also asynchronously but under conditions less severe than the asynchronous automatic reclosures (AARC). Thus, the high-speed ARC devices reclose the line without the preceding short-time or prolonged asynchronous operation. Successful high-speed automatic reclosure is followed only by decaying synchronous swings.

Because of the short no-power interval, the HSARC is effective only in the case of short-time faults, such as flashovers in damp weather, lightning arc-overs, etc. To obtain HSARC, high-speed breakers are necessary to have short no-power intervals. In the USSR the HSARC systems are employed only on lines equipped with air circuit breakers. The HSARC can also be accomplished with thyristor switches now under development.

The no-power time of the HSARC permitted according to the parallel operation stability is determined by calculating the stability. Roughly, it is found as follows: during the short circuit and the tie link tripped state the emf vectors must not be parted by an angle greater than the critical angle δ_{cr} at which reclosures without asynchronous operation are still possible.

The angle δ_{cr} is assumed approximately 60-70 degrees. If, under before-fault conditions the angle $\delta_n = 20$ degrees, then during HSARC the angle increases

$$\delta_{12} = \delta_{cr} - \delta_n = 40 \text{ to } 50 \text{ degrees} \tag{8-7}$$

If the generators with load P_l are working into an infinite-power system through a tie line, then, when the line is broken and supposing that the rotor motion is uniformly accelerated, we may write in correspondence with (8-2)

$$\delta_{12} = \frac{1}{2} \frac{P_l}{P_n} \frac{\omega_n}{T_{in}} t^2, \text{ rad} \tag{8-8}$$

Since $\omega_n = 2\pi f_n$ when $T_{in} = 10$ s, we have

$$\delta_{12}^0 = \frac{1}{2} \cdot \frac{360}{2\pi} \frac{2\pi 50}{10} \frac{P_l}{P_n} t^2 = 900 \frac{P_l}{P_n} t^2 \tag{8-9}$$

From (8-8) and (8-9) the no-power critical time of the breaker, i.e., the time during which the auxiliary contacts remain open, can be roughly calculated.

If $P_l/P_n = 1$,i.e., if it is supposed that the generators fully work into the tie line and that $\delta_{12}^{0} = 50$ degrees from (8-9) we find that

$$t = 0.23 \text{ s}$$

The HSARC devices are used only on lines furnished with high-speed protection means. With the protection operating time of 0.04 s, the no-power time of the breaker should be 0.19 s. As the arc-extinguishing time of the breaker is 0.06 s, the time left to deionize the arc space on the transmission line is 0.13 s. As mentioned before, this time is the minimum permissible to prevent the arc restriking after the deenergization of a 110 kV transmission line.

An increase in the HSARC no-power time adds to the arc extinguishing and restoration of the insulation. However, the risk of disturbances to the synchronism between the parts of the power system rises as well.

It follows from (8-9) that an increase in the no-power (current) time may be tolerated when only a part of the generation is transmitted over the tie line. This can be so when some amount of generation is consumed by the local loads, when the generators are partially loaded, or special measures are provided to automatically reduce the output of the generators (turbines) which accelerate after tripping the tie link (by emergency braking the generators through adding resistances to the stator circuit, or rapidly stopping steam admittance).

When installing HSARC devices, performing reclosures at considerable angles δ_{12}, measures should be taken to prevent misoperation of the protection due to equalizing currents. This should be done in a manner similar to that used when installing an asynchronous ARC device.

In the Soviet Union high-speed air breakers are available without an external isolator, but with an internal isolating switch inside the circuit breaker reservoir. The arc chutes of the breakers have a carrying capacity of 2,000 amperes and a breaking capacity of 6,000 MVA.

The 500-kV circuit breaker has 10 arc chutes connected in series. The arc chutes are connected in series with an air-filled isolator. The isolator has four similar break sets each of which includes a stationary contact and a moving one.

With the breaker in the *closed* position there is no compressed air in the arc chute and isolator spaces. To trip the circuit breaker, compressed air is forced to the arc chutes. The appropriate valves are controlled by a pusher coupled with the core of the tripping coil. The arc is extinguished by a jet of compressed air when the contacts of the arc chutes are open.

Simultaneously compressed air is supplied through non-return valves to the pistons of the isolators, their contacts are parted and form a gap giving the required dielectric strength. The contacts are held in this position by compressed air and then the arc chute contacts make.

When compressed air is supplied in the tripping cycle of the breaker, the moving contacts of the isolator compress the return springs, therefore to *close* the breaker it is only necessary to open the release valve. This valve is actuated by the core of the closing coil.

The HSARC operations on the breakers is accomplished by a closing pulse fed from an *ordinary* ARC device. The pulse time overlaps total time sufficient for arc extinction in the arc chute and for deionizing the arc space at the point of fault (0.2 s for 110-220-kV lines and 0.35-0.4 s for 330-500-kV lines). After this, the contacts of the arc chute close to complete again the current-carrying circuit. When the automatic reclosure is ineffective, as the fault persists, the protection system repeats its action and the breakers are tripped completely.

For low-speed ARC breakers with internal isolators the closing pulse must be fed by the ARC device as soon as the isolator contacts have fully parted. This is why the dead time (no-power time), during such an automatic reclosure, includes the time taken by the isolator contacts to part a distance to suit the dielectric strength of the formed gap (0.14 to 0.16 s) and the breaker reclosing time (0.8 to 1.0 s).

HSARC may be used in conjunction with other types of automatic reclosures (for instance, with OPARC on single lines and with TPARC on parallel lines; in the latter case, when parallel links are available and when the tripping of one of the lines does not disturb the synchronism, use is made of TPARC and, when the parallel link is disconnected for repair, of HSARC servicing the remaining single line).

ARC devices which seize synchronism (*ARCSS*) are applied on single tie lines and on tie lines having small carrying capacity bypass links, if the use of AARC or HSARC is impossible. The ARCSS device seizes the convergence of frequencies of the asynchronously operating parts of the power system or indicates that the difference of the frequencies lies within the specified value. The device sends a control pulse to reclose the breaker when the frequency difference reaches a certain value, and so that the reclosure takes place at small phase angles between the voltages (50 to 70 degrees). The ARCSS device allows for possible reclosures at frequency differences up to 4 per cent (1.5-2.0 Hz). Since the reclosure takes place at small angles, the ARCSS operations cause no perceptible current surges or asynchronous operation. Sometimes the reduction of the slip between the asynchronously operating parts, required for accomplishing ARCSS, is possible only after the use of stand-by power or the unloading of the power system part lacking generation (manually or by means of AFC devices). After tripping a tie line and disturbance to the synchronism between the source of generation, this line is reclosed at one end of the transmission line when it has no voltage, and at the other end of the line when a voltage occurs (appears) in step with the busbar voltage.

The circuit of the ARC device is similar to that shown in Fig. 8-4, plus relays responding to no-voltage across the line or the busbars or to absence of voltage synchronism on the busbar and line (Fig. 8-15).

Waiting for no-voltage is achieved by applying the d.c. negative pole to the coil of relay *TR* (Fig. 8-4) via the contacts of voltage relay U_l at the line voltage. The time delay of time relay *TR* is greater than the time to clear a short circuit at the opposite end of the line. It is assumed that with a line short circuit the end of the line furnished with the ARC device is disconnected quickly, for instance by the first stage of the distance protection, and from the other end

it is disconnected slowly, for instance by the second or third stage of the protection.

Synchronism seizing at the other end of the line by means of the ARC device is accomplished because the d.c. negative pole is applied to the time relay TR only when the angle between the vectors of the line and busbar voltages does not exceed the angle at which the synchronism check relay closes its contacts. If the line and busbar voltages are in step, the synchronism check relay will keep its contacts closed and the relay TR will function to promote the reclosure. If the vector speeds of the line and busbar voltages are different, i.e., there is a beat (Fig. 8-16), the device operates as follows: the relay TR operates within the zone between points *1* and *2*, as in this zone the synchronism check relay holds its contacts closed (point *1* corresponds to the relay reset instant and the closure of its contacts and point *2*, to the relay pickup instant and opening of these contacts).

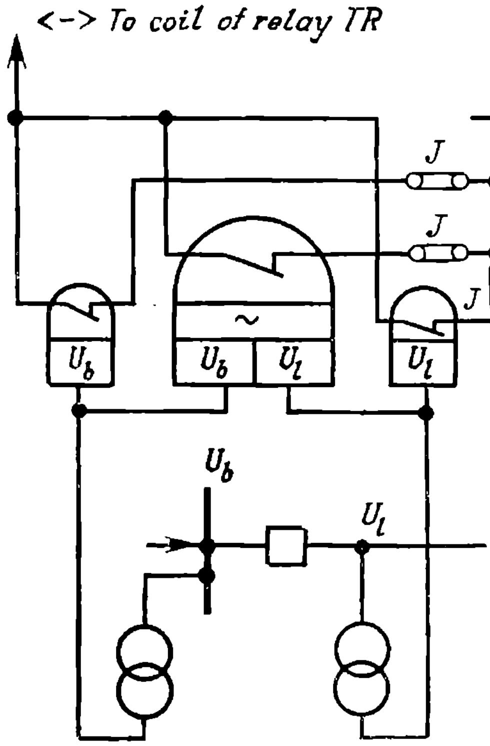


Fig. 8-15. ARC device which seizes synchronism

A control pulse to close will be given if the time the contacts are closed is greater than or is equal to the time relay setting $t_{relay\ TR}$.

Point *3* is determined by the t_{pickup} setting of the synchronism check relay. This setting should be selected so that when a closing pulse is fed at point *2* the breaker is closed at point *3* with a critical angle not greater than $\delta_{cr} = 70$ to 75 degrees.

Usually the pickup angle δ_{pickup} is between 40 to 55 degrees. With a reset-to-pickup ratio of 0.80, the reset angle $\delta_r = 32$ to 46 degrees. Thus, the time relay operates within the range of angles δ_{12}

$$\delta_{12} = \delta_{pickup}(1 + k_r) \tag{8-10}$$

where k_r is the reset-to-pickup ratio of the synchronism check relay.

If the frequency difference, i.e., the beat frequency

$$f_s = f_1 - f_2 \tag{8-11}$$

the angle between the emf vectors changes in 1 s by

$$\delta^\circ = 360 f_s \tag{8-12}$$

The angle turn by δ°_{12} will correspond to the time

$$t = \frac{\delta^\circ_{12}}{300 f_s} \tag{8-13}$$

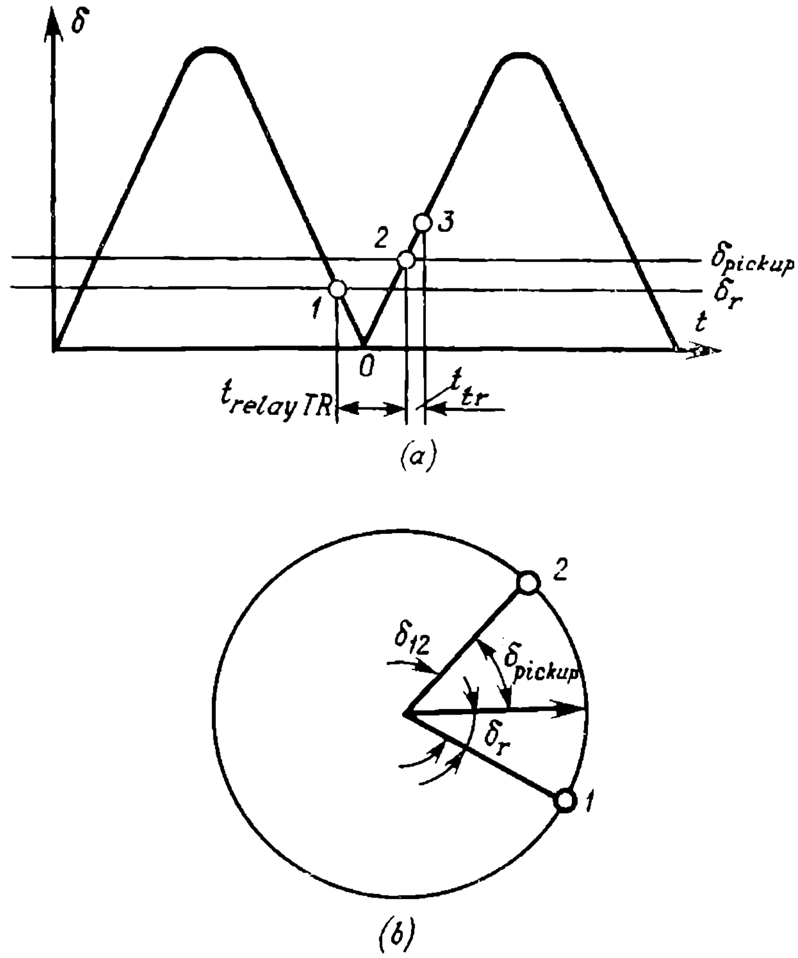


Fig. 8-16. Operation of ARC device with synchronism seizing
(a) changes of angle between emf vectors in asynchronous operation; (b) operating range of time relay of ARC device (the range area is limited by angle δ_{12})

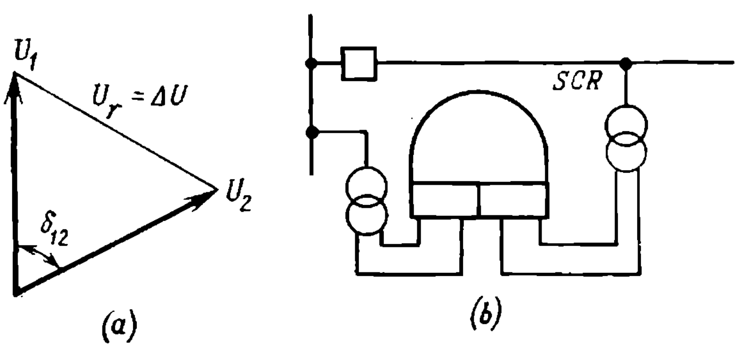


Fig. 8-17. Synchronism check relay
(a) diagram explaining operating principle; (b) relay connection diagram

If the pickup time of the time relay is t_{pickup} the beat frequency

$$f_s=\frac{\delta^{\circ}_{12}}{360t_{pickup}}=\frac{\delta^{\circ}_{pickup}(1+k_r)}{360t_{pickup}} \tag{8-14}$$

When $k_r = 0.8$, $\delta_{pickup} = 40°$, and $t_{pickup} = 2$ s

$$f_s=\frac{40}{360\cdot 2}(1+0.8)=\frac{40\cdot 1.8}{360\cdot 2}=0.1 \text{ Hz}$$

When $k_r = 0.85$, $\delta_{pickup} = 55°$, and $t_{pickup} = 2$ s

$$f_s=0.14 \text{ Hz}$$

Used in the device shown in Fig. 8-17 as the relay checking the angle δ_{pickup} is a relay responding to the vector difference between the voltages. Such a relay

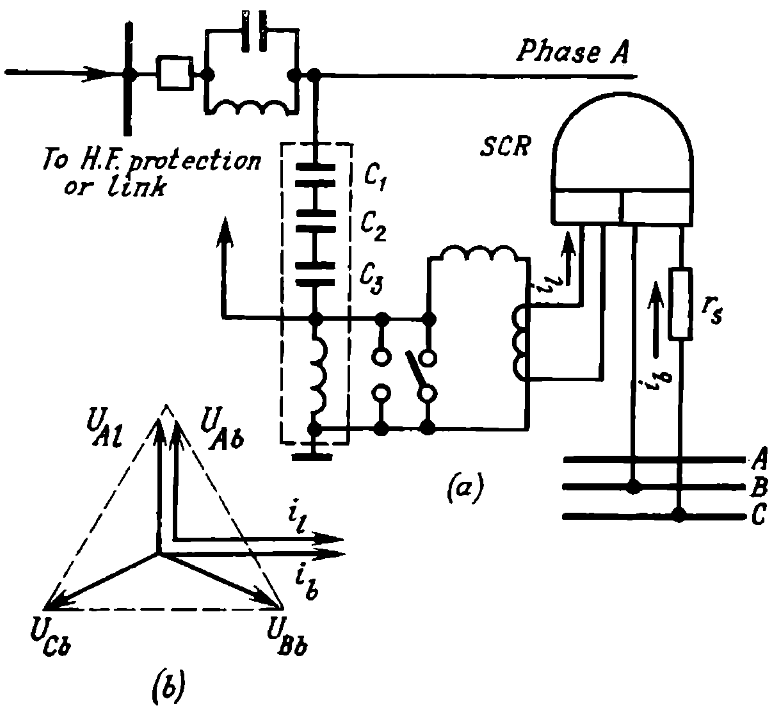


Fig. 8-18. Connection of synchronism check relay to coupling capacitor on the line and to voltage transformers on busbars

(a) connection diagram; (b) vector diagram

may be a voltage relay whose coils are opposing each other. Applied to one coil is the busbar voltage, while the other relay coil is at the line voltage taken from a voltage transformer or from a device for capacitor voltage take-off which is connected to the line (Fig. 8-18).

The relay picks up if the resulting flux in the relay core is greater than the flux corresponding to the pickup voltage.

To comply with Fig. 8-17*a*

$$|\dot{U}_{pickup}|=|\Delta\dot{U}|=|\dot{U}_1-\dot{U}_2| \tag{8-15}$$

Corresponding to the pickup voltage U_{pickup} is the angle δ_{pickup}. If $|\dot{U}_1| = |\dot{U}_2|$, then

$$\Delta U = 2U \sin \frac{\delta_{12}}{2} \tag{8-16}$$

Being given the required setting of angle δ_{pickup} the voltage across the relay may be determined as follows

$$U_{pickup} = 2U \sin \frac{\delta_{pickup}}{2} \tag{8-17}$$

When the relay range is limited, the angle between the voltage vectors (δ_{pickup}), at which the relay picks up, can be widened if one coil of the relay is connected to the voltage U_{A0} and the other, to the voltage $-U_{C0}$. In this instant the additional shift between the voltage vectors will amount to 60 degrees. If one of the relay coils is connected to the voltage U_{A0} and the other, to the voltage $A_{AC}/\sqrt{3}$, the additional shift will be 30 degrees. Thus, with a relay whose pickup setting adjustment reaches 40 degrees, the pickup setting range may be enlarged to 70 or 100 degrees. Taking into account the possibility when the angle between the vectors of the busbar and line voltage changes its sign, which characterizes what part of the power system before the fault was receiving or sending real power, a second relay is used.

For example, if one relay functions at a pickup angle adjustable within the range from plus 70 to minus 10 degrees, the other relay has a setting range from minus 70 to plus 10 degrees, i.e., the setting range is ± 70 degrees.

At the initial stages of the practical use of the ARCSS devices, reclosures were performed at frequency differences of 0.5 to 1 Hz. To improve the operation efficiency of the ARC device with synchronism seizing, the Belorusenergo designed a scheme which ensures parallel operation reclosures at frequency differences ranging from 0 to 1.9 Hz with a maximum angle error of ± 45 degrees.

The ARC device operates as follows (Figs. 8-19 and 8-20)[8-3].

Two synchronism check relays are installed with an operation setting angle of 45 degrees. The setting is adjusted directly on the relay by changing the spring load or connecting the relay to the busbar and line voltages shifted in phase. The relay *1SCR* is installed so that with the phases coincident the resulting m.f. equals zero and the spring holds the contacts *1SCR-2* closed. The relay *2SCR* is connected so that with the phases coincident the resulting m.f. is at its maximum and as a result the closing contacts *2SCR-1* are closed.

When the angle between the vectors of the voltages being synchronized is less than 45 degrees, the relay *1SCR* supplies power via the tripping contacts *1SCR-2* to the coil of relay *1ATR*. The latter has a dropout delay of 0.15 s.

The tripping contacts of relay *1SCR* break and its closing contacts make when the phase angle between the voltages exceeds 45 degrees. As this happens, the time relay *1TR* picks up and the coil of the relay *1ATR* becomes deenergized. After the contact of *1ATR* has opened, the time relay *1TR* remains energized through the self-holding circuit, as it is connected by the instantaneous contact *1TR-1*.

If the frequency difference is small (less than 0.7 Hz), the time relay functions until the angle exceeds 360— 45 = 315 degrees and promotes the self-holding after the contacts *1SCR-1* open. The contacts *1SCR-2* close and, as the contact *1TR-2* continues to be closed, the output relay AR_{out} functions and closes the breaker.

If the contacts *1SCR-1* open till the operation of the contact *1TR-3*, i.e., if the frequencies differ by more than 0.7 Hz, the coil of the time relay becomes deenergized and the circuit of the AR_{out} is opened by the contact *1TR-2* before the contacts *1SCR-2* have closed.

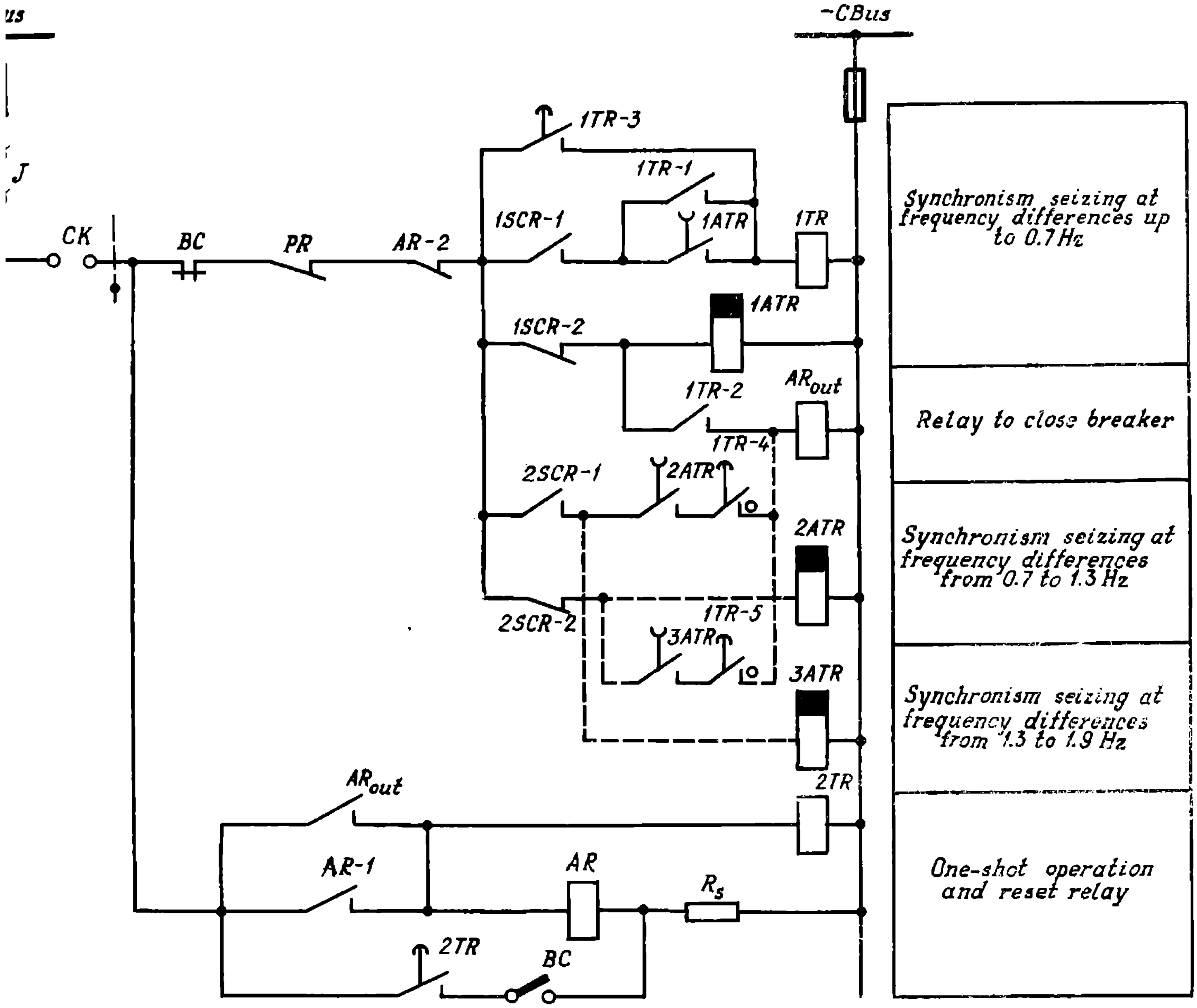


Fig. 8-19. ARC device with synchronism seizing

PR — contact of pressure relay (when use is made of air breaker); *BC* — blocking contacts of breaker

When the frequencies being synchronized differ by 0.7 to 1.3 Hz, the relay sliding contact *1TR-4* has time to operate from the instant the contact *2SCR-1* closes and the contact *2SCR-2* opens. As this happens, the relay AR_{out} functions.

To close the breaker at a frequency difference from 1.3 to 1.9 Hz, a part of the circuit (dashed line in Fig. 8-19) is added, and the relay *1TR* is supplemented with sliding contact *1TR-5*.

The operation of the device is clear from Fig. 8-20*c*.

Single reclosures and resetting operations are promoted by the relays *2TR* and *3AR*.

The two-end supply lines are susceptible to one-end trippings (if an arc is extinguished when one end is tripped quicker than the other with an abrupt current drop in the arc channel, or due to malfunction of a protection device during a short circuit at the adjacent feeders or lines). If the tripping occurs where the line no-voltage condition is detected automatic reclosure will not take place if a voltage is present due to the generation source at the other end.

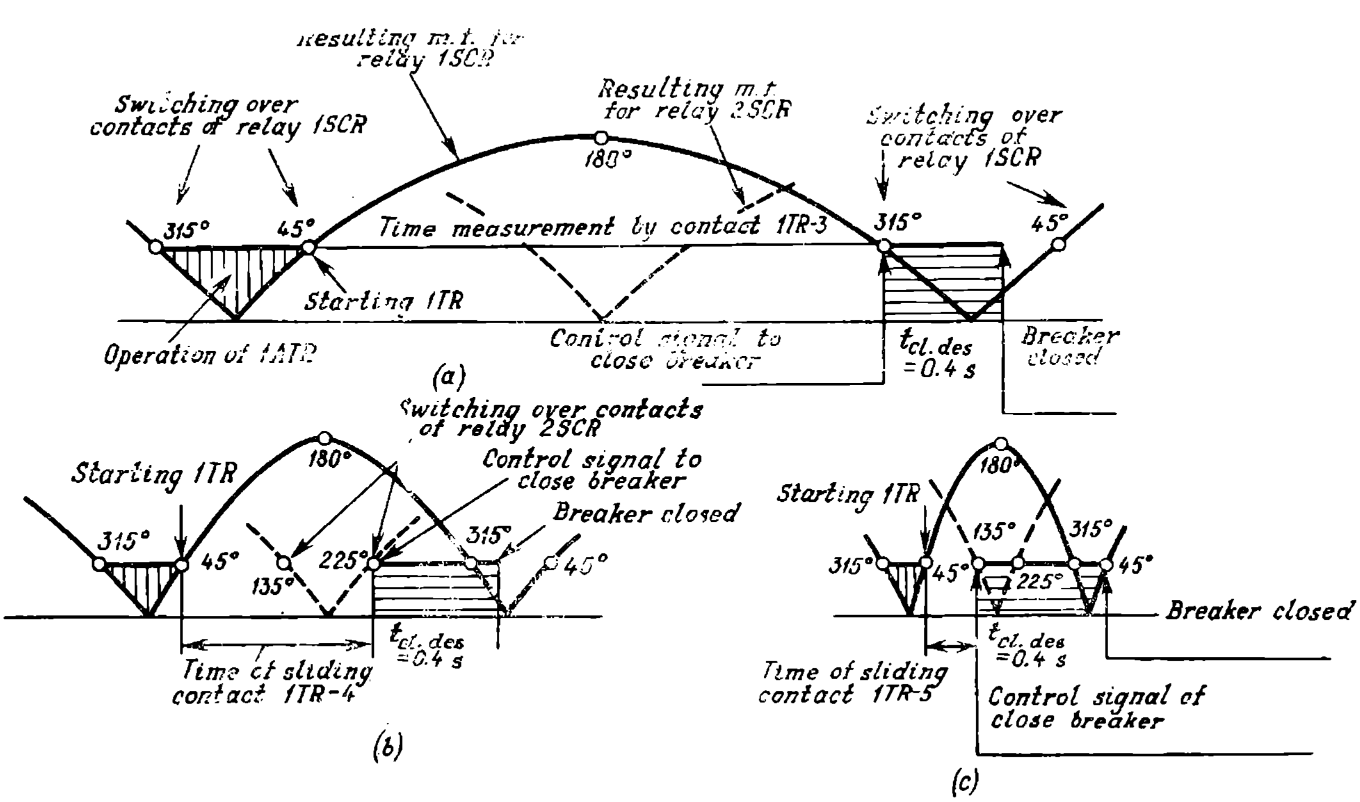


Fig. 8-20. Operating diagram of ARC device circuit (Fig. 8-19) depending on the difference between frequencies of the voltages being synchronized

(*a*) connection at frequency differences up to 0.7 Hz; (*b*) same at frequency difference from 0.7 to 1.3 Hz; (c) same at frequency difference from 1.3 to 1.9 Hz; $T_{cl.des}$ — design closure time from the instant the command signal is given to the instant the contacts of the breaker are closed (taken as 0.4 s)

Therefore, in many cases a no-voltage check relay (with a view to promoting the line tests) and a synchronism seizing relay (with the object of closing for parallel operation) are installed. The automatic reclosure time is set so that the breakers at both ends cannot be simultaneously closed when the line is tripped at both ends.

When the line tripping from both ends may render the busbars of the substation connected to one of the ends deenergized (for example, due to disconnection of the generating plant), the ARCSS device cannot function. In this case, in parallel with the contacts of the relay controlling the voltage synchronism the contacts of the relay responding to the no-voltage condition of the busbars are connected. When there is no voltage across the busbars ARC operation of the line breaker is allowed.

Therefore, the circuit of the ARC device must include a voltage relay to allow the breaker to be reclosed when no voltage exists across the busbars, a synchronism relay waiting for the synchronism of the line and busbar voltages, and a voltage relay responding to the line no-voltage condition. All the three relays function when there is no voltage across the line and busbars, and the corresponding relays operate when there is no voltage across the line or across the busbars. These relays respond to the no-voltage condition and when the line and the busbars have a voltage, the synchronism seizing relays function (Fig. 8-15).

The synchronism seizing ARC device waits for the time when parts of the power system may be paralleled. This is why such ARC devices may be regarded as plain automatic synchronization devices facilitating the work of the operators accomplishing synchronism when, on the order of the dispatcher, the frequencies of the sectionalized parts of the power system are equalized prior to subsequent paralleling, or when the conditions causing the ARC operation come after the AFC devices have operated in the part of the sectionalized power system where real power is lacking.

8-4. Tie Lines and Parallel Links

When attempting automatic line reclosures in a ring-type system, the following facts should be considered:

(a) Disconnection of one line should not interrupt the power supply to consumers or disturb the electrical link between substations. Thus, the operating time of the ARC devices may be somewhat longer, than in the case of a line with one supply end. However, the operating time of the ARC devices should not be too long, as a rapid reclosure may prevent the break of the electrical link between substations due to the tripping of other lines (from frequent lightning surges, in particular where no overhead earth wires are used).

Moreover, line reclosures prevent overloads to the other lines of the ring network.

Automatic reclosures are of particular importance when unattended substations serving transmission lines are not equipped with remote-control line breakers. If ARC devices are not available, the reclosure operations will take much time with prolonged abnormal operation of the circuit.

(b) An ARC operation can be effective if the breakers at both ends of the line are reclosed after the line has been tripped at both ends, otherwise the arc at the point of fault may persist and the line disconnects again.

(c) A ring circuit may have one or several power-supply points. Substations of the ring circuits *with one power-supply point* may turn out to be under one-end supply conditions when one of the lines is disconnected for repair. In such conditions, each effective automatic reclosure prevents prolonged interruptions in power supply.

The ring lines employ ARC devices of the same type as the lines supplied at one end. The ARC devices are installed at the line ends and make the breaker reclose after its tripping.

Sometimes to simplify the protective relaying system, a ring circuit (with one power-supply point) is disconnected to form two parts. In such instances the power supply to these parts with a line short circuit is accomplished as if the substations are fed from one end. The loads of one part of the circuit are switched over to the other part manually or automatically only in the case of ineffective operation of the ARC device.

On two parallel links, ARC devices without synchronism check are installed if, when one link is tripped the other link is permitted to asynchronously close after its opening. If asynchronous reclosures cannot be tolerated the lines of a ring circuit are equipped with ARC synchronism seizing devices.

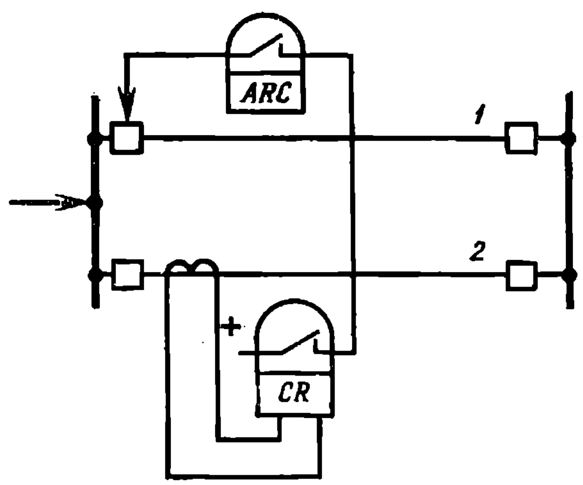


Fig. 8-21. ARC device circuit with checking for synchronism

When three and more parallel links are available between the power stations of *a ring network with several power-supply points* simultaneous disconnection of all the links is considered unlikely. That is why it is not necessary to use more elaborate ARC devices. The lines are furnished with ARC devices without synchronism check as it is in a ring circuit supplied from one point. Taking into account that faults may occur repeatedly during repairs, ARC devices providing synchronism checks are sometimes used. Such ARC devices ensure tripped lines reclosures only when the bypass links remain in operation, i.e., when the power-supply sources operate synchronously. The ARC devices incorporate elements which check the voltage synchronism on both sides of the breaker being reclosed. ARC operations are prohibited if these voltages lose synchronism; this may happen when all bypass links are tripped.

The ARC synchronism seizing devices and synchronism checking ARC devices differ from each other in that the former automatically perform reclosures when the synchronism is sustained or, in the case of disturbances to the synchronous operation, "siezes" the most favourable instant to give a control pulse to reclose the breaker at a fairly large slip, while the latter accomplishes automatic reclosures after a preassigned time lapse if the synchronism is not disturbed during this time, or conditions arise under which the disturbance slip decreases to a permitted value.

The ARC devices *for parallel lines* have the same underlying principles as the lines of a ring system. Use is made of the above-described ARC devices, in particular the ARC devices with synchronism seizing and AARC devices where asynchronous reclosures are permissible. The specific configuration of the circuit allows parts of the power system to be checked for synchronism after one of the parallel lines without relay checking the voltages for synchronism is tripped.

This is accomplished by a current relay connected to the current of the other operating line.

The operating principle of the circuit is seen from Fig. 8-21.

Automatic reclosures on line *1* are allowed when the current relay connected to one of the current transformers of line *2* functions and vice versa. If the ARC device is made according to the circuit diagram in Fig. 8-4 the presence of current may be checked by exciting the circuit of the coil of time relay *TR* included in the ARC unit of one of the parallel lines, through the contacts of a current relay whose coil carries the current of the other line.

In order that the current relay trips the contact for sure when the line is tripped at the other end, the reset setting of the relay should be greater than the value of the line capacity current.

8-5. TPARC Devices on Air Circuit Breakers

The tripping of an air circuit breaker from an ARC device is permitted only when the compressed air pressure in the breaker reservoirs, before the first tripping of the breaker, is sufficient to accomplish the completion of the first tripping operation, the reclosure from the ARC device, and another tripping if the short circuit persists.

With air circuit breakers rated at 35 to 500 kV the minimum pressures at which the manufacturer guarantees reliable short circuit clearing are tabulated in Table 8-3.

Table 8-3

Compressed Air Pressures at which Air Circuit Breakers Clear Short Circuits

Type of breaker	Minimum pressure at which the breaker can clear a short circuit, kgf/cm^2	Pressure drop during phase interruption at rated pressure, kgf/cm^2
BBH-35	15	2.5-3
BBH-220/7000	16	2.5-3
BBHR-500	16	3
Breakers of other types	18	3

As tripping a breaker decreases the compressed air pressure by 3 kgf/cm^2, the pressure available after the first tripping before the reclosure from an ARC device should be, to allow for possible reclosure due to a persisting short circuit, greater than the minimum value at which the breaker can clear a short circuit by 3 kgf/cm^2. This pressure is not less than 18 kgf/cm^2 for BBH-35 breakers, not less than 19 kgf/cm^2 for BBH-220/7000 and BBHP-500 breakers, and not less than 21 kgf/cm^2 for other types. These calculations take into account the fact that the compressed air consumption for closing the breaker is small and that

the compressed-air loss is replenished in the tripping-reclosing-tripping cycle from compressed-air mains.

Certain air breakers control circuits provide adjustment of the compressed-air pressure and the trigger circuit of the ARC device by an electrical pressure gauge as shown in Fig. 8-22. The ARC device will operate only when the pressure indicated by the pressure gauge *PG*, after tripping the breaker and closing the contacts of the opening solenoid *OS*, exceeds the pickup setting. In this case, the relay *AR*, which holds itself closed by its *AR-1* contact, function and completes the ARC device triggering circuit by its *AR-2* contact. The relay *AR* remains closed until the self-holding circuit is broken at the contact of the breaker closing solenoid (*CS*). A likely pressure decrease in the opening-closing cycle does not stop the action of the ARC device.

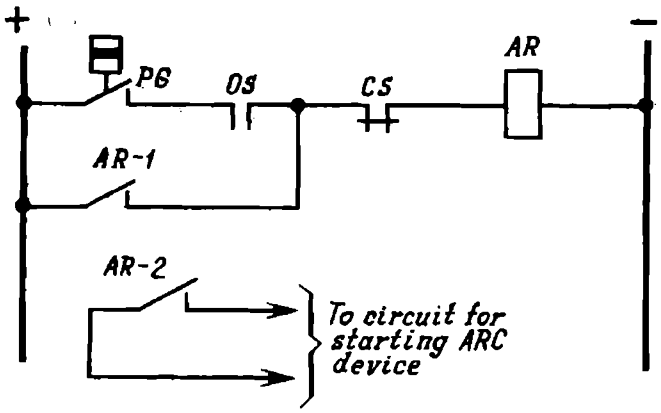


Fig. 8-22. Circuit for control of starting circuits of ARC device in air breakers by means of electrical pressure gauge

In order to make the operation of the breaker control device independent of pressure drops likely to occur during its functioning, provision is made to

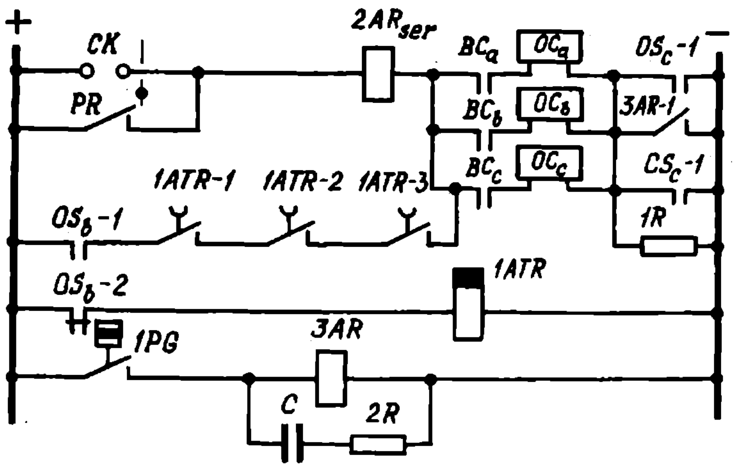


Fig. 8-23. Control circuits of air breaker

CK — contact of control key; *PR* — contact of output protection relay; *OS* — contacts on solenoids of opening coils (in phases *B* and *C*); *CS* — contacts on solenoids of closing coils; B_a, B_b, B_c— blocking contacts closed when *A*, *B* and *C* phases of breaker are closed; *1ATR*—relay with dropout delay up to 5 s; $2AR_{ser}$— series coil of relay blocking against multi-shot reclosures; *3AR* — auxiliary relay; *C* and *R* — capacitor and resistor to improve arc extinguishing

bypass the repeater relay contacts which control the air pressure by the blocking contacts of the electromagnetic closing and opening coils. In addition, to ensure reliable tripping of the air breakers, provision is made to "pick up" the tripping pulse with subsequent interlocking after the breaker has tripped for about 5 s.

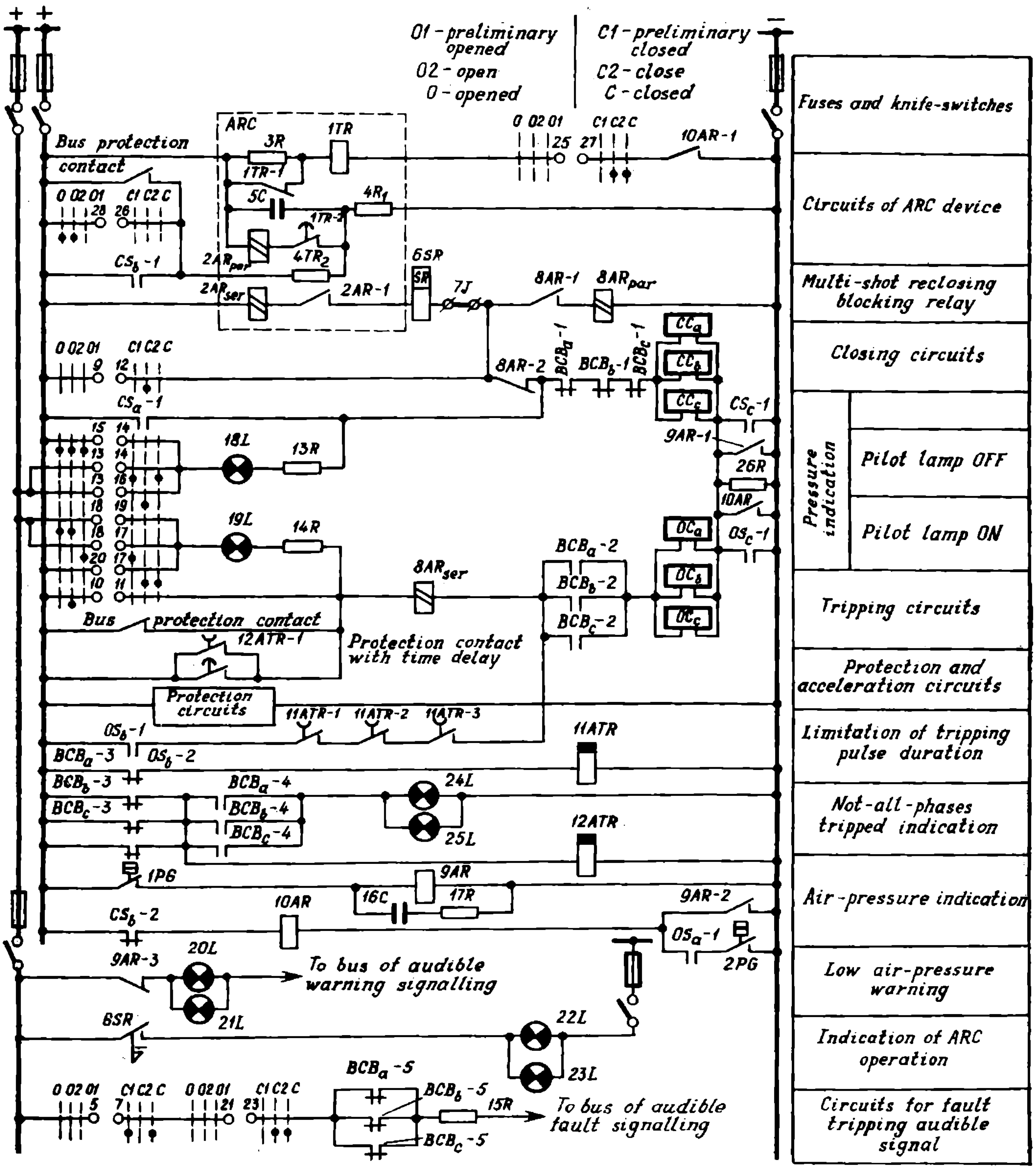


Fig. 8-24. Schematic diagram of control, signalling and air breaker ARC circuits with light indication of the condition of operating circuits

1TR — time relay; *2AR* — auxiliary relay; *3R*, $4R_1$, $4R_2$ — series resistors; *5C* — capacitor (element of ARC device); *6SR* — signalling relay; *7J* — jumper; *8AR* — auxiliary two-coil relay; *9AR* and *10AR* — auxiliary relays; *11ATR*, *12ATR* — relay delayed in reset; *13R*, *14R*, *15R* and *17R* — series resistors; *16C* — capacitor; *18L* through *25L* — pilot lamps; *26R* — series resistor; *1PG*, *2PG* — electrical pressure gauges; *CK* — control key; BCB_a, BCB_b, BCB_c — blocking contacts of breakers of phases *A*, *B*, *C*; CS_a, CS_b, CS_c — blocking contacts of closing coil solenoids of phases *A*, *B*, *C* breakers; OS_a, OS_b, OS_c — blocking contacts of opening coil solenoids of phases *A*, *B*, *C* breakers

To facilitate the operation of the contacts of relay *ATR* (a relay delayed in dropout up to 5 s) performing the deblocking operations, use is made of three series-connected contacts (Fig. 8-23).

The circuit with light monitoring of the condition of the operative lines for control, signalling and automatic reclosing of air breakers is schematically

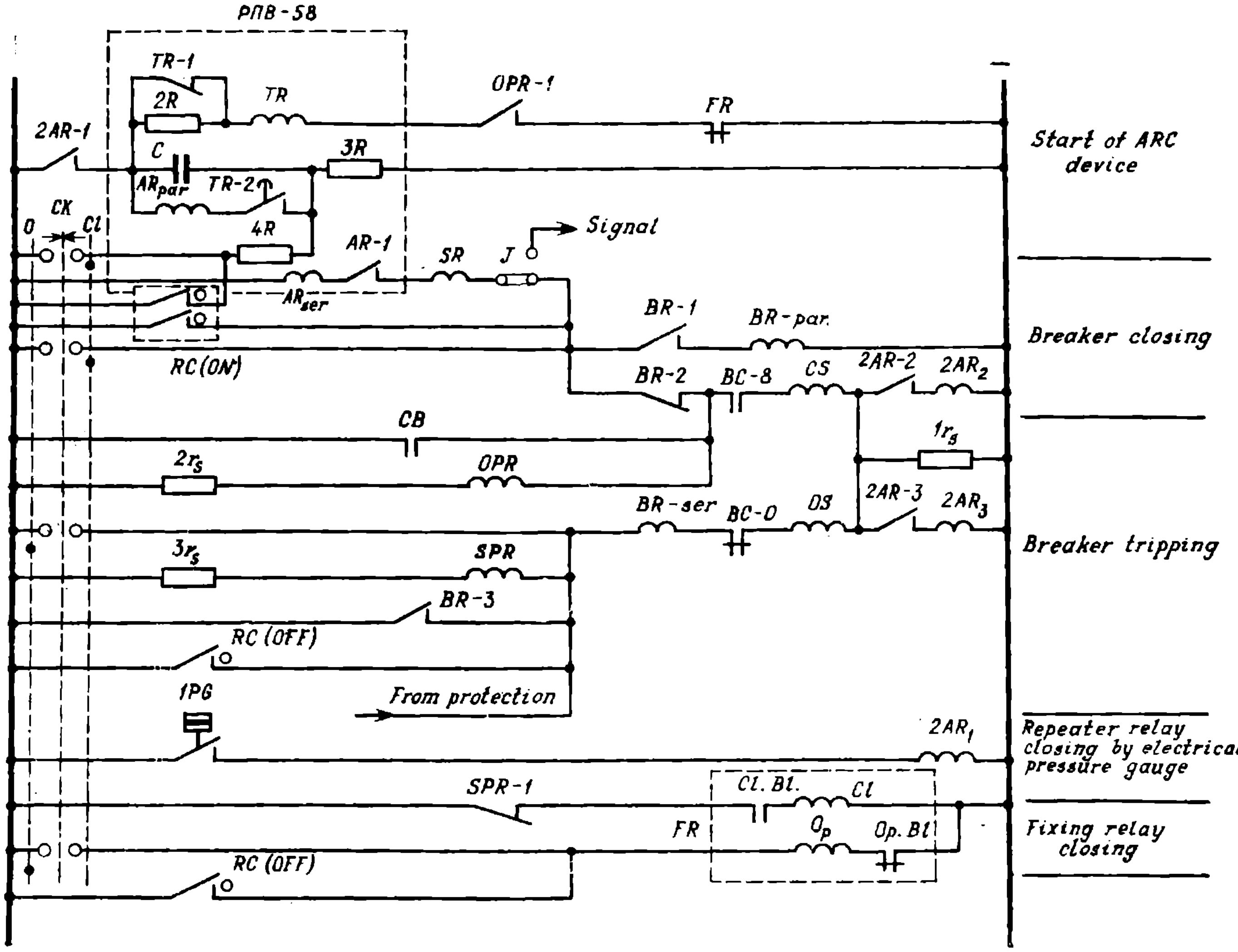


Fig. 8-25. Control circuit of air breaker with ARC device waiting for pressure recovery

FR —two-position relay

illustrated in Fig. 8-24. This diagram shows the above-mentioned pickup of the tripping pulse, which may not be used for the BB-200, BB-220 and BB-400 breakers having devices for the pneumatic pickup of the control pulses.

Figure 8-25 shows one more variant of the ARC circuit of air circuit breakers. A specific feature of this variant is its ability to perform automatic reclosures with waiting for the pressure to build up to the rated value (16 kgf/cm²) when it has dropped during the accomplishment of the control pulse clearing a short circuit.

The circuit employs a two-position fixing relay *FR*, type РП-352. When a discrepancy arises between the position of this relay and that of the breaker, in the case of its disconnection from the protection device, the contact of relay *FR* closes the circuit of the ARC device relay, type РПВ-58 (see Fig. 8-4). Use is made of a control key with automatic return to the neutral position. When the breaker is closed by the control key or by a remote-control device (*RC*), a prohibiting pulse is fed to the ARC device by the discharge of capacitor *C* through resistor *4R*. This prevents the breaker from automatic reclosure, when it is being closed manually to a short circuit.

The compressed-air pressure is indicated by the electric pressure gauge *1PG*. When the pressure drops below 16 kgf/cm^2 the pressure gauge contact opens and breaks the coil circuit of relay *2AR* (coil $2AR_1$). In this case, the *2AR-2* and *2AR-3* contacts open to remove the operating current from the closing and opening coils of the breaker which must not operate at pressures below 16 kgf/cm^2.

If the pressure is restored the contact of *1PG* makes and the relay *2AR* functions. The closing-opening circuit of the breaker is recovered as well as the circuit of the ARC device which is completed by the contact *2AR-1* (with the coil of $2AR_1$ deenergized, the contact *2AR-1* is open with the result that the ARC device is automatically disconnected when the compressed-air pressure is below 16 kgf/cm^2).

Connected in series with the contacts *2AR-2* and *2AR-3* are holding coils $2AR_2$ and $2AR_3$. This is to complete a closing or opening operation if during their execution the compressed-air pressure becomes less than 16 kgf/cm^2, a fact likely to happen for a short time.

To improve the reliability of the operating circuit, the contacts *2AR-2* and *2AR-3* with their holding coils $2AR_2$ and $2AR_3$ are connected in parallel. Resistor $1r_s$ (500 ohms) helps the operation of the position relay *CPR* and *CPR* even when the air pressure becomes less than 16 kgf/cm^2.

8-6. Conclusions

1. ARC devices are very important as they improve the operation reliability of power systems. Newly developed three-phase ARC devices for lines supplied from one end or two ends are now in service in the USSR.

2. The ARC devices used on lines supplied at one end are specially important as their efficient operation prevents outages with prolonged interruptions to the power supply. Installation of two- or even three-shot ARC devices is advisable.

3. For tie lines between power stations and/or parts of the power system the use of an asynchronous ARC device gives good results in all cases when the mechanical efforts in the generators and transformers caused by asynchronous reclosures do not exceed the rated values, and when asynchronous reclosures are followed by rapid resynchronization. In this case the protective relaying system must be adapted to the operation of the AARC.

4. The expediency of ARC use in a sectionalized area should be considered for a given power system, and with a synchronous load supplied from the power system through a single transmission line, the operation of the ARC device at

the supplying end must be coordinated with the automatic control devices which change over the synchronous load (synchronous capacitors and motors) to operation with discharged field and accomplish the subsequent resynchronization after effective reclosures.

5. The operating time of the ARC devices should be as short as practicable, but sufficient to extinguish an open arc and deionize its space after clearing the fault. The operating time of the ARC device must include the line tripping time from both ends and for lines supplied from one end, also the decaying time of the voltage sustained by the coasting of the asynchronous and, in particular, the synchronous load.

6. The circuit breakers installed on the transmission lines must allow for the use of ARC devices. Air circuit breakers must have sufficient compressed air to perform reclosures with allowance for the possibility of connecting to a persisting short circuit. The accomplishment of high-speed automatic reclosures needs specially designed circuit breakers and quick-acting protection for the lines. The HSARC devices give good results in instances when the synchronism of paralleled parts of the power system is not disturbed during the dead time and the arc space can be deionized.

7. For the lines of a ring system supplied at several points the design of ARC devices must be considered from the point of view of maintaining synchronism and the possibility of asynchronous reclosures.

8. When in service, operational specifications should be adhered to, in particular [8-1].

(a) When installing ARC devices consumers' consent is not required.

(b) When for some reason ARC devices are not installed on a line supplied from both ends or they are temporarily absent (inoperative) one end of the line must be furnished with an ARC device able or not able to check for opposite voltage, so that the line can be automatically voltage tested with the aim of facilitating its subsequent reclosure.

(c) When overhead lines rated at any voltage, cable lines up to 35 kV; busbars and transformers without ARC devices are automatically tripped (if this does not disturb the power supply), the operators must immediately reclose them one time without warning the consumers, inspecting the equipment or undertaking other operations.

Excepted from this are lines, busbars and transformers to which an asynchronous voltage may be applied with current surges dangerous to the machines. When undertaking asynchronous connections, attending personnel must consider the possibility of asynchronous operation and take measures to eliminate it.

(d) With overhead lines, single reclosure must be performed, when no ARC device is available or if it is at fault, also in the cases when the power supply is not disturbed. One reclosure must be performed manually (if attended or equipped with remote-control means), also after an ineffective reclosure, if the tripping disturbs the power supply or limits the number of consumers due to overloading of the lines remaining in operation.

(e) The list of lines for which manual reclosing is compulsory after ineffective automatic reclosure must be established beforehand.

8-7. Review Questions

1. Why does the cause of the fault often disappear after clearing a short circuit? What is meant by an effective automatic reclosure? What determines the efficiency of ARC devices? What accounts for the effective operation of ARC devices on cable circuits?

2. Why is the percentage of effective two-shot automatic reclosures greater than that of single automatic reclosures?

3. Describe the conditions determining the minimum operating time of ARC devices on the lines supplied at one end and at two ends.

4. ARC devices on overhead transmission lines adds to the reliable operation of these lines during thunder storms. How do you explain this fact?

5. An ARC device installed on a 110-kV one-end supply line is under repair. The line has disconnected from the protection system. May you reclose it immediately manually without preliminary inspection of the equipment?

6. May a line rated at 35 to 220 kV supplying a power system area, be closed manually after it has been tripped by a protection unit, reclosed by an ARC device and again tripped by the protection unit?

7. What are the operating time limits for single, two-shot and three-shot automatic reclosures performed on lines supplying power to loads from one end?

8. What are the advantages and disadvantages of the ARC devices started from a protection unit as compared with ARC devices started when the breaker and the control key are in different positions?

9. How is ARC operation prohibited in the device shown in Fig. 8-4?

10. What makes the ARC devices perform single action and two-shot action? Sketch a circuit blocking the repeated reclosures of circuit breakers.

11. The coils of relay *2AR* (see Fig. 8-4) are wrongly connected and the magnetic fluxes arising when current flows in the coils during the operation of the ARC devices and during feeding of a closing pulse are opposite to one another. Will the ARC device operate reliably? What should be done to change the polarity of the magnetic flux induced in the series coil?

12. Draw a diagram of an ARC device suitable for installation on transmission lines run from the busbars of a substation under remote-control (unattended substation).

13. Determine the time taken by the ARC device in Fig. 8-4 to be ready for operation after the circuit breaker is closed manually.

The voltage across the storage battery $U_{bat} = 110\ V$, the pick-up voltage of *2AR* relay $U_{pickup} = 22$ V and the capacitance of capacitor $C = 20$ μF.

Solution. After the breaker is closed by the contactor, the capacitor C starts to charge. The relay *2AR* will be able to function if at the moment its coil is activated by a voltage whose magnitude, determined by the voltage U_C across the capacitor, becomes greater than the pickup voltage U_{pickup}.

The moment the capacitor is connected to the relay coil, the voltage across the terminals of the coil of relay *2AR* starts to decrease to the law

$$U_C = Ue^{-t/R_rC} \tag{8-18}$$

where U_C = voltage across the capacitor
U = voltage to which the capacitor was charged
t = time, s
R_r = resistance of the coil of relay *2AR*

Since the relay *2AR* takes a certain time to operate, it is necessary for the voltage across the capacitor terminals to be at least 2.5 to 3.5 times the pickup voltage of the relay *2AR*[8-8], i.e., it must be

$$U_C = k_s U_{pickup} \tag{8-19}$$

where k_s = 2.5 to 3.5. More accurately k_s (safety factor) for actual types of relays is determined experimentally.

The capacitor is charged to the law

$$U_C = U_{bat}(1 - e^{-t/RC}) \tag{8-20}$$

where R is the charging resistance. In the example we assume R = 1.1 Mohm.

Easily determined from (8-19) and (8-20) is the charging time t_{charge} after which the voltage across the capacitor reaches the value at which the relay $2AR$, being connected to the capacitor, will reliably function. After this the capacitor starts to discharge through the coil of the relay

$$t_{charge} = RC \ln \frac{U_{bat}}{U_{bat} - k_s U_{pickup}} \tag{8-21}$$

Hence

$$t_{charge} = 1,100,000 \cdot 20 \cdot 10^{-6} \ln \frac{110}{110 - 3 \cdot 22} \tag{8-22}$$

$$t_{charge} = 22 \ln 2.5 \approx 20 \text{ s}$$

14. Estimate the different methods of establishing ARC devices on single tie lines between two parts of a power system. Under what conditions is it permitted to perform asynchronous automatic reclosures?

15. Give an evaluation of different methods of accomplishing ARC devices on transmission lines of a ring system supplied at several points.

16. Determine the tentative dead time of HSARC operations when the generators carry full load and supply half the power to the power system through a single line furnished with a HSARC device. The critical angle $\delta_{cr} = 80$ degrees and the initial angle $\delta_{in} = 20$ degrees. The inertia constant $T_{in} = 15$ s.

17. May a HSARC device be used on a 500-kV single transmission line which carries the full power of the hydroelectric generators loaded to their rated output? The minimum dead time when the arc is deionized is 0.4 s. The inertia constant $T_{in} = 10$ s.

18. May an automatic synchronizer be used in an ARC with synchronism seizing?

19. What are the specific ways of fulfilling protective relaying devices when AARC devices are installed?

20. What are the actions of the operators, when the transmission line is tripped when the tripping coincides in time with the checking operation of the ARC device (the ARC device was disconnected)?

Chapter Nine

ONE-PHASE AUTOMATIC RECLOSURE OF POWER TRANSMISSION LINES

9-1. Earth Fault and Tripping of One Phase

In electrical power systems which have the neutrals of transformers and autotransformers earthed, the power when one of the phases is tripped, can be transmitted through the damaged section. As the electrical resistance of the section with one phase tripped rises, the amount of the power being carried should be reduced (to roughly 2/3 of the full power carrying capacity). With persistent one-phase short circuits on lines supplied at one end, on single lines supplied at both ends and also on lines with laterals, this circumstance allows the section at fault to be changed over to continuous operation through a two phases—earth scheme [9-1].

Detecting a fault on the phase conductor, the tripping, reclosure and subsequent disconnection of this phase or the whole section at fault are carried out by one-phase ARC devices (PARC). As changing over to operation with a two phases—earth circuit requires a number of manual operations (tripping the isolators on the phase at fault, changing the settings of protective relaying and ungrounding some of the neutral conductors to reduce the effect on the communication wires), the function of the PARC device is, in most cases, to disconnect the faulty section with three phases after an unsuccessful reclosure. This makes the PARC device more simple.

The best results are obtained from the one-phase (phase-after-phase) automatic reclosure on single-circuit tie lines carrying heavy loads. As compared to three-phase reclosures, the no-power (dead) time (as dictated by stability) may be tens of times greater (Fig. 9-1) [9-2].

The disadvantages of the use of phase-after-phase automatic reclosure are as follows:

Appearance of considerable zero-sequence currents flowing in earth under the two phases—earth conditions, which needs special measures to reduce the effect upon the communication wires.

Necessity of using phase-after-phase breakers and their phase-after-phase control which makes the secondary circuits more intricate and increases the length and the number of cores used in the control cable.

An increase in the system costs as required by installation of circuit breakers at the receiving end of single lines supplied at one end.

The devices used for detecting a faulty phase and the protective relaying units operating together with these devices become more complicated.

When one of the phases of the circuit with a dead-earthed neutrals is at an earth fault, the voltage of the faulty phase, say phase A in Fig. 9-2, at the point of fault is zero.

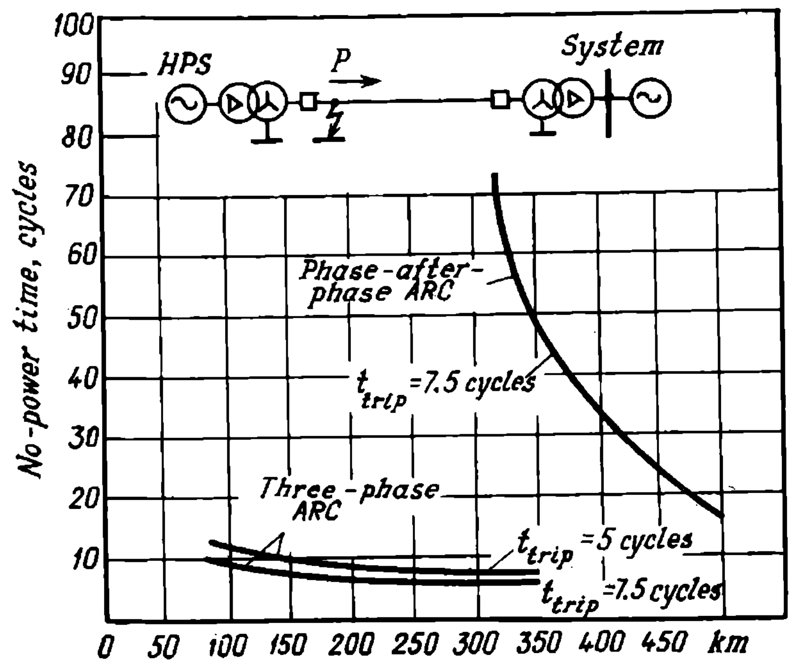


Fig. 9-1. Permissible no-power time due to tripping one or three phases with subsequent reclosure versus distance and type of three-phase or phase-after-phase ARC device as dictated by the stability of power transmission line over which the power station supplies power to power system

t_{trip} — fault tripping time

The current at the point of short circuit

$$\dot{I}_{Asc} = \frac{\dot{E}_A - 0}{z} = \frac{\dot{E}_A}{z}$$

where z = impedance equivalent to that of the short-circuit loop

$\dot{E}_A$ = nominal emf value of phase A

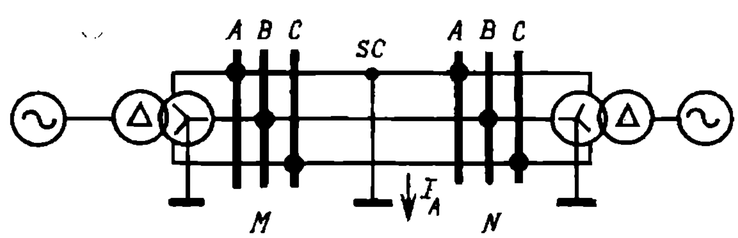


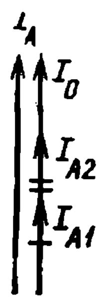
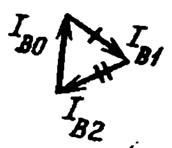
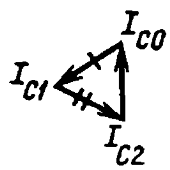
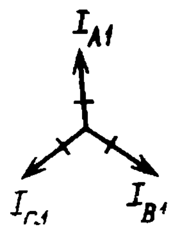
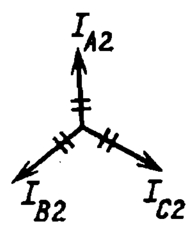
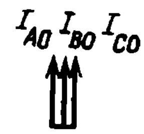
Fig. 9-2. Currents at one-phase earth-fault point in circuit with heavy earth-fault current

Using the method of symmetrical components, this current can be presented as a vector sum of forward-, backward- and zero-sequence currents (Table 9-1)

$$\dot{I}_{Asc} = \dot{I}_{A1sc} + \dot{I}_{A2sc} + \dot{I}_{0sc} \tag{9-1}$$

Table 9-1

Currents at Short-Circuit Point when Phase *A* is at Earth Fault

Phase currents at short-circuit point			Symmetrical components of currents		
			Sequence of phases		
A	B	C	forward	backward	zero
$\dot I_A=\dot I_{Asc}$ $\dot I_A=\dot I_{A1}+$ $+\dot I_{A2}+\dot I_0$	$\dot I_B=0$ $\dot I_B=\dot I_{B1}+$ $+\dot I_{B2}+\dot I_0$	$\dot I_C=0$ $\dot I_C=\dot I_{C1}+$ $+\dot I_{C2}+\dot I_0$	$\dot I_{A1}=\frac{1}{3}\times$ $\times(\dot I_A+a\dot I_B+$ $+a^2\dot I_C)$	$\dot I_{A2}=\frac{1}{3}\times$ $\times(\dot I_A+a^2\dot I_B+$ $+a\dot I_C)$	$\dot I_0=\frac{1}{3}\times$ $\times(\dot I_A+$ $+\dot I_B+\dot I_C)$
					

The currents in the undamaged phases are $\dot I_{Bsc}=0$ and $\dot I_{Csc}=0$; thus

$$0=\dot I_{B1sc}+\dot I_{B2sc}+\dot I_{0sc}$$

and

$$0=\dot I_{C1sc}+\dot I_{C2sc}+\dot I_{0sc}$$

These conditions and condition (9-1) are satisfied if

$$\dot I_{A1sc}=\dot I_{A2sc}=\dot I_{0sc} \tag{9-2}$$

and

$$\dot I_{Asc}=3\dot I_{0sc} \tag{9-3}$$

Currents $\dot I_{A1sc}$, $\dot I_{A2sc}$ and $\dot I_{0sc}$ are accompanied by corresponding sequences in the system of voltages.

For phase *A* at the point of short circuit the voltage

$$\dot U_A=\dot U_{A1sc}+\dot U_{A2sc}+\dot U_{0sc}=0 \tag{9-4}$$

The voltages $\dot U_{A2}$ and $\dot U_{A0}$ decrease and the voltage $\dot U_{A1}$ increases proportional to the distance from the point of short circuit.

At the substation M the voltage of this or that sequence equals the vector sum of the voltages of the given sequence at the point of fault and the voltage drop of the corresponding sequence due to the impedance of this sequence

$$\left.\begin{aligned} \dot{U}_{A1M} &= \dot{U}_{A1sc} + \dot{I}_{A1}^{Msc} z_{1Msc} \\ \dot{U}_{A2M} &= \dot{U}_{A2sc} + \dot{I}_{A2}^{Msc} z_{2Msc} \\ \dot{U}_{A0M} &= \dot{U}_{A0sc} + \dot{I}_{A0}^{Msc} z_{0Msc} \end{aligned}\right\} \tag{9-5}$$

Msc denotes in (9-5) the circuit section between the substation M and the point of short circuit *sc*.

Taking into account (9-5), we determine the faulty phase voltage at the point of the relay installation at substation M

$$\dot{U}_{AM} = \dot{I}_{A1}^{Msc} z_{1Msc} + \dot{I}_{A2}^{Msc} z_{2Msc} + \dot{I}_{A0}^{Msc} z_{0Msc} \tag{9-6}$$

The voltages of backward and zero sequences across the power source are zero, as the emf vectors form a symmetric three-phase system. For this point (9-5) may be presented as follows:

$$\dot{E}_{A1} = \dot{E}_{nA} = \dot{U}_{A1sc} + \dot{I}_{A1sc} \Sigma z_1 \tag{9-7a}$$

$$0 = \dot{U}_{A2sc} + \dot{I}_{A2sc} \Sigma z_2 \tag{9-7b}$$

$$0 = \dot{U}_{0sc} + \dot{I}_{0sc} \Sigma z_0 \tag{9-7c}$$

where $\dot{E}_{nA}$ = nominal emf of the phase A

Σz_1, Σz_2, and Σz_0 = system forward-, backward- and zero-sequence impedances reduced to the point of short circuit

An equivalent circuit for the short-circuit calculations is determined through the analysis of (9-7).

As at a single-phase short circuit the short-circuit point satisfies conditions (9-2) and (9-4), we have

$$\dot{E}_{nA} = \dot{I}_{0sc} (\Sigma z_1 + \Sigma z_2 + \Sigma z_0) \tag{9-8}$$

Thus, the equivalent circuit must represent a series connection of the impedances Σz_1, Σz_2 and Σz_0 (reduced to the point of short circuit) which are at the nominal phase emf (Fig. 9-3).

The current at the point of short circuit

$$\dot{I}_{Asc} = \frac{3\dot{E}_{nA}}{\Sigma z_1 + \Sigma z_2 + \Sigma z_0} \tag{9-9}$$

The current at any point of the circuit is determined as a sum of currents flowing through the system section under consideration in compliance with the current distribution in the circuits of forward, backward and zero sequencies. If the line is supplied at one end (for example, from the M side), the impedances $z_{1N} = z_{2N} = \infty$ and the equivalent circuit has the form shown in Fig. 9-3*b*.

With an open circuit in one phase, say phase A (Fig. 9-4), the current in this phase is zero and the voltage between the m and n open-circuit points is $\dot{U}_A$.

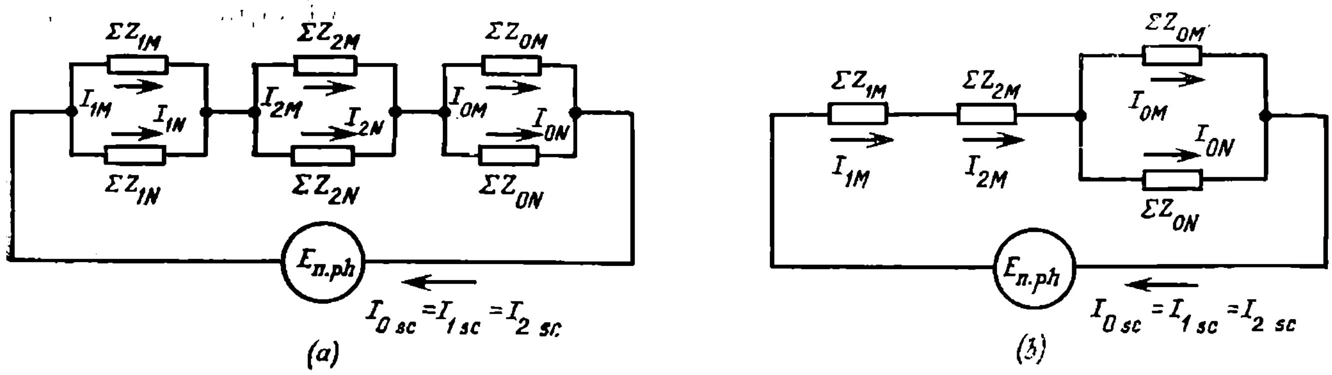


Fig. 9-3. Equivalent circuit for calculating currents during one-phase short circuit with dead-earthed neutral

(a) general case; (b) for line supplied at one end with earthed neutrals of the transformers at the supplying and receiving ends

This voltage may be presented as originating of direct-axis (longitudinal emf) voltage across the open circuit gap

$$\Delta\dot{E}_{oc}=\dot{U}_A \tag{9-10}$$

being superimposed on the symmetric voltage system of the before-fault operation.

It follows from the above that, as in the two phases—earth operation, the system currents and voltages become asymmetric and current flows to earth during the PARC cycle (the PARC cycle time is the time elapsed from the instant a phase of the line is tripped to the instant it is reclosed). The value of the earth current is roughly about the same as the load current in the open-circuited phase under the before-fault conditions. To make the calculations of currents more accurate we proceed as follows. As the current $\dot{I}_A = 0$, then, in accordance with the basic relationships of the symmetrical component method, we have

$$\dot{I}_A=\dot{I}_{A1}+\dot{I}_{A2}+\dot{I}_0=0 \tag{9-11}$$

The components of the forward, backward and zero sequence of the direct-axis voltage at the point of open circuit are

$$\dot{U}_{A1}=\dot{U}_{A2}=\dot{U}_0=\frac{1}{3}\dot{U}_A \tag{9-12}$$

These components of the direct-axis voltage are applied between the open-circuit points m and n of the equivalent circuits of the forward, backward and zero sequencies.

In compliance with (9-2) the points m_1, m_2, and m_0 from one side of the open circuit are at similar potentials and may be interconnected. The points from the other side of the break n_1, n_2 and n_0 are also equipotential.

The circuit used for calculations is similar to that shown in Fig. 9-4*b*. In the case of a one-end supply, the circuit has the form shown in Fig. 9-4*c*.

The equations determining whether the equivalent circuit is suitable for the purpose can be obtained analytically. Since the set of equations (9-7) is

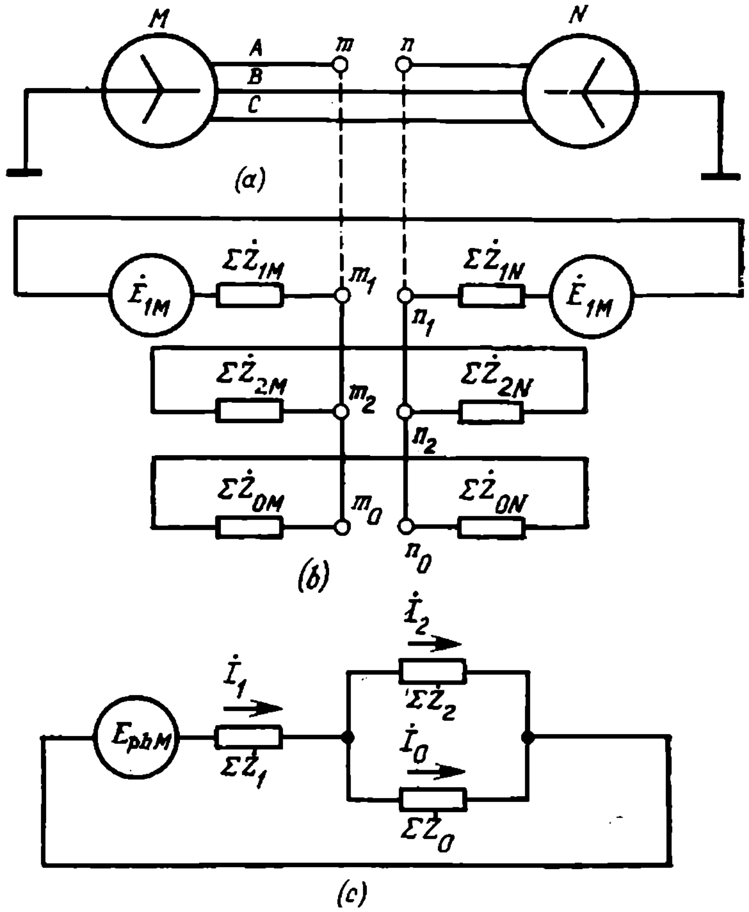


Fig. 9-4. Equivalent circuit with one open-circuited phase

(*a*) circuit diagram; (*b*) equivalent circuit, general case; (*c*) equivalent circuit when line is supplied at one end

common to any asymmetric operation, we assume that $\dot{E}_{1M} = \dot{E}_{1N} = E_{n.ph}$ and then, after subtracting expression (9-7*b*) and then (9-7*c*) from (9-7*a*), we obtain

$$\dot{E}_{n.ph} = \dot{I}_{A1}\Sigma z_1 - \dot{I}_{A2}\Sigma z_2 \tag{9-13a}$$

and

$$\dot{E}_{n.ph} = \dot{I}_{A1}\Sigma z_1 - \dot{I}_0\Sigma z_0 \tag{9-13b}$$

In compliance with (9-11)

$$\dot{I}_{A2} = -(\dot{I}_{A1} + \dot{I}_0) \tag{9-14}$$

Hence, (9-13*a*) may be presented as

$$\dot{E}_{n.ph} = \dot{I}_{A1}\Sigma z_1 + (\dot{I}_{A1} + \dot{I}_0)\,\Sigma z_2 = \dot{I}_{A1}(\Sigma z_1 + \Sigma z_2) + \dot{I}_0\Sigma z_2 \tag{9-15}$$

After solving (9-13b) and (9-15) and eliminating I_0, we obtain

$$\dot{E}_{n.ph}(\Sigma z_2+\Sigma z_0)=\dot{I}_{A1}\,[\Sigma z_1\Sigma z_2+\Sigma z_1\Sigma z_0+$$
$$+\Sigma z_2\Sigma z_0]=\dot{I}_{A1}\,[\Sigma z_1(\Sigma z_2+\Sigma z_0)+\Sigma z_2\Sigma z_0]$$

or

$$\dot{E}_{n.ph}=\dot{I}_{A1}\left[\Sigma z_1+\frac{\Sigma z_2\Sigma z_0}{\Sigma z_2+\Sigma z_0}\right] \tag{9-16}$$

Thus, the equivalent impedance of the equivalent circuit includes the forward-sequence impedance reduced to the open-circuit point, which is series-connected to the parallel connected backward- and zero-sequence impedances.

Cascade disconnection of phase at earth fault. To analyse the operation of the protective relaying and discriminating elements of PARC devices, it is important to know how the

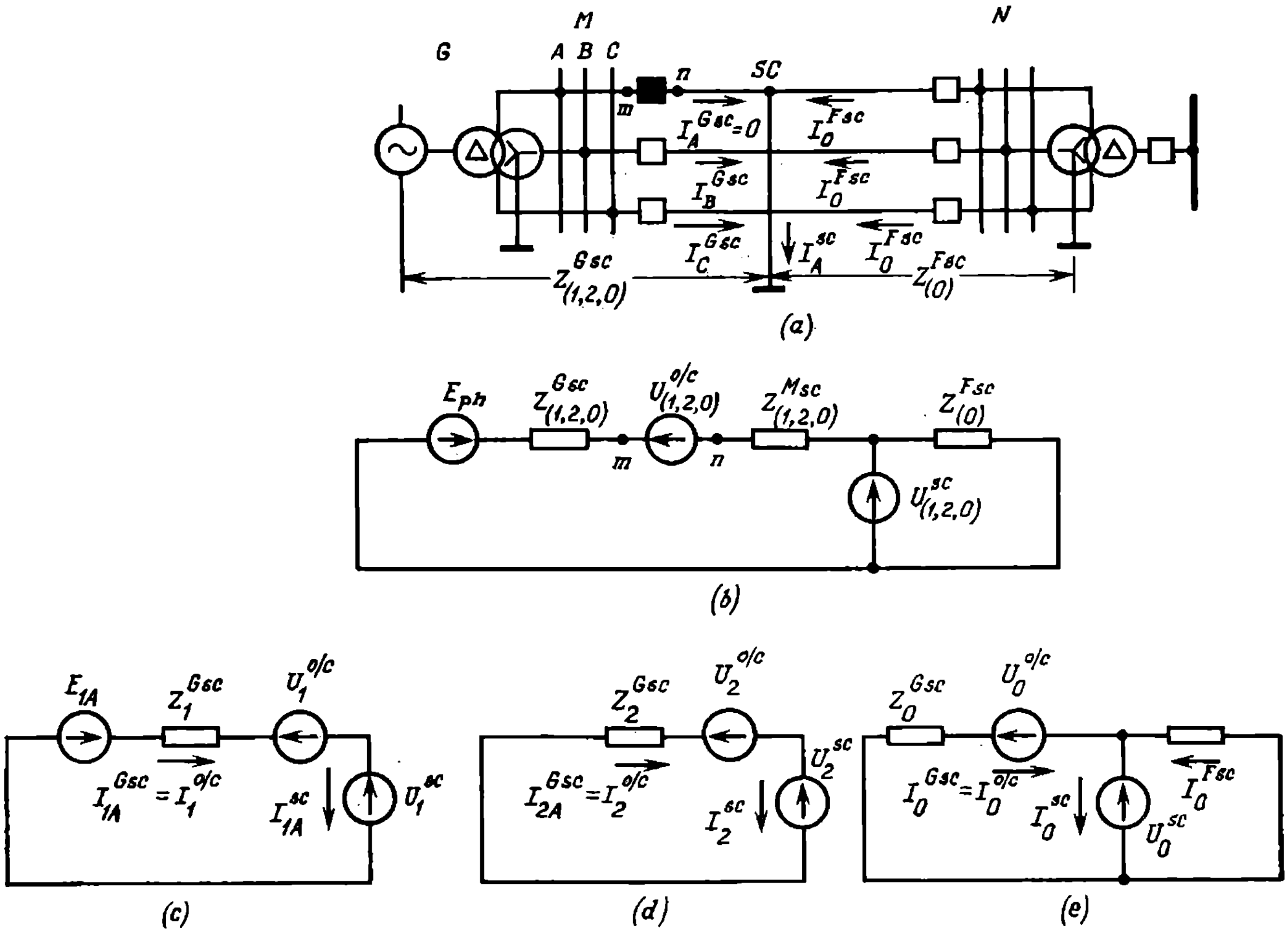


Fig. 9-5. One-side tripping of faulty phase in the PARC cycle during one-phase short circuit of phase A

(a) circuit diagram (figures 1, 2 and 0 correspond to forward, backward and zero sequences); (b) equivalent circuit; (c-e) forward-, backward-, and zero-sequence circuits (shown in black is the breaker of tripped phase)

current and voltage values vary during cascade one-side tripping of the faulty phase at the supply end of the transmission line (Fig. 9-5) when the phase A is disconnected from the side of substation M. On the N substation side all the three phases remain connected.

We assume a three-phase system where, in addition to the emf $\dot{E}_{ph}$ the emf $\dot{U}_{oc}$ applied across the break $m - n$ and the voltage $\dot{U}^{sc}$ at the short-circuit point act. The joint effect of the emf and voltages is such that the conditions for current distribution among the phases of the three-phase circuit, which are characteristic of the asymmetric operation under consideration, are satisfied. These conditions are [9-3]:

(a) No current flows in the faulty phase $\dot{I}_A^{Gsc} = 0$ at the point of open circuit.

(b) With a lateral at short circuit, no current flows in the sound phases $\dot{I}_A^{sc} = \dot{I}_C^{sc} = 0$ and the faulty phase carries $\dot{I}_A^{sc} = \dot{I}_\Sigma^{sc}$.

(c) Since no generation is supplied from the substation F and the neutral conductor of the transformer of substation F is earthed, the same current equal to the zero-sequence current flows in all phases through the section $F - sc$ to the point of short circuit

$$\dot{I}_A^{Fsc} = \dot{I}_B^{Fsc} = \dot{I}_C^{Fsc}; \quad \dot{I}_1^{Fsc} = \dot{I}_2^{Fsc} = 0$$

(d) The faulty phase voltage at the point of one-phase short circuit is zero $\dot{U}_A^{sc} = 0$.

From the calculation diagrams of the separate sequences of currents, voltages and impedances (Fig. 9-5*c* through *e*) it is seen, that

$$\dot{I}_{1A}^{Gsc} = I_{1A}^{oc} = I_{1A}^{sc} \tag{9-17}$$

$$\dot{I}_{2A}^{Gsc} = \dot{I}_{2A}^{oc} = I_{2A}^{sc} \tag{9-18}$$

$$\dot{I}_0^{sc} = I_0^{oc} + \dot{I}_0^{Fsc} \tag{9-19}$$

$$\dot{I}_0^{sc} = \dot{I}_0^{Gsc} + I_0^{Fsc} \tag{9-20}$$

With closed electrical circuits the sum of the emf and voltage drops is zero, therefore: from Fig. 9-5*c*

$$\dot{E}_{1A} - \dot{U}_{1A}^{oc} - \dot{U}_{1A}^{sc} = \dot{I}_{1A}^{oc} z_1^{Gsc} \tag{9-21}$$

from Fig. 9-5*d*

$$-\dot{U}_{2A}^{oc} - \dot{U}_{2A}^{sc} = \dot{I}_{2A}^{oc} z_2^{Gsc} \tag{9-22}$$

from Fig. 9-5*e*

$$-\dot{U}_0^{oc} - \dot{U}_0^{sc} = \dot{I}_0^{oc} z_0^{Gsc} \tag{9-23}$$

Since, according to the condition characteristic of the asymmetry under consideration

$$\dot{I}_A^{oc} = 0$$

then

$$\dot{I}_{1A}^{oc} + \dot{I}_{2A}^{oc} + \dot{I}_0^{oc} = 0$$

i.e.

$$\dot{I}_0^{oc} = -(\dot{I}_{1A}^{oc} + \dot{I}_{2A}^{oc}) = 0 \tag{9-24}$$

As $\dot{I}_B^{sc} = \dot{I}_C^{sc} = 0$ it follows, that

$$\dot{I}_{1A}^{sc} = \dot{I}_{2A}^{sc} = \dot{I}_0^{sc} = \frac{\dot{I}_A^{sc}}{3} \tag{9-25}$$

Since $\dot{I}^{sc}_{1A} = \dot{I}^{oc}_{1A}$ (Fig. 9-5*c*)
and

$$\dot{I}^{sc}_{2A} = \dot{I}^{os}_{2A} \text{ (Fig. 9-5}d\text{)}$$

with (9-25) taken into account, expression (9-24) may be transformed as follows

$$\dot{I}^{oc}_{0} = -2\dot{I}^{sc}_{1A} \tag{9-26}$$

From Fig. 9-5*e* it is seen that

$$-\dot{U}^{sc}_{0} = \dot{I}^{Fsc}_{0} z^{Fsc}_{0} \tag{9-27}$$

With account of (9-20), we find

$$-\dot{U}^{sc}_{0} = (\dot{I}^{sc}_{0} - \dot{I}^{Gsc}_{0})\, z^{Fsc}_{0} \tag{9-28}$$

After substituting the value of U^{sc}_{0} from (9-28) into expression (9-23), we have

$$-\dot{U}^{oc}_{0} = \dot{I}^{oc}_{0} z^{Gsc}_{0} - (\dot{I}^{sc}_{0} - \dot{I}^{Gsc}_{0})\, z^{Fsc}_{0} \tag{9-29}$$

Since

$$\dot{I}^{sc}_{0} = \dot{I}^{sc}_{1A} = \dot{I}^{oc}_{1A}$$

and

$$\dot{I}^{Gsc}_{0} = \dot{I}^{oc}_{0} = -2\dot{I}^{sc}_{1A} = -2\dot{I}^{oc}_{1A} \tag{9-30}$$

then

$$-\dot{U}^{oc}_{0} = -2\dot{I}^{oc}_{1A} z^{Gsc}_{0} - (\dot{I}^{oc}_{1A} + 2\dot{I}^{oc}_{1A})\, z^{Fsc}_{0}$$

$$-\dot{U}^{oc}_{0} = -2\dot{I}^{oc}_{1A} z^{Gsc}_{0} - 3\dot{I}^{oc}_{1A} z^{Fsc}_{0} \tag{9-31}$$

Adding the right and left sides of expressions (9-21), (9-22) and (9-23), and taking into account, that $\dot{U}^{sc}_{0} = 0$, i.e., $\dot{U}^{sc}_{1A} + \dot{U}^{sc}_{2A} + \dot{U}^{sc}_{0} = 0$ and at the point of open circuit $\dot{U}^{oc}_{B} = \dot{U}^{oc}_{C} = 0$ and $\dot{U}^{oc}_{1A} = \dot{U}^{oc}_{2A} = \dot{U}^{oc}_{0}$, we obtain

$$\dot{E}_{1A} - 3\dot{U}^{oc}_{0} = \dot{I}^{oc}_{1A} z^{Gsc}_{1} + \dot{I}^{oc}_{1A} z^{Gsc}_{2} + \dot{I}^{oc}_{0} z^{Gsc}_{0}$$

With (9-30) taken into account

$$\dot{E}_{1A} - 3\dot{U}^{oc}_{0} = \dot{I}^{oc}_{1A} z^{Gsc}_{1} + \dot{I}^{oc}_{1A} z^{Gsc}_{2} - 2\dot{I}^{oc}_{1A} z^{Gsc}_{0}$$

$$\dot{E}_{1A} - 3\dot{U}^{oc}_{0} = \dot{I}^{oc}_{1A} (z^{Gsc}_{1} + z^{Gsc}_{2}) - 2\dot{I}^{oc}_{1A} z^{Gsc}_{0} \tag{9-32}$$

Substituting the value of U^{oc}_{0} from (9-31) into this expression, we have

$$\dot{E}_{1A} - 6\dot{I}^{oc}_{1A} z^{Gsc}_{0} - 9\dot{I}^{oc}_{1A} z^{Fsc}_{0} = \dot{I}^{oc}_{1A} (z^{Gsc}_{1} + z^{Gsc}_{2}) - 2\dot{I}^{oc}_{1A} z^{Gsc}_{0}$$

hence

$$\dot{E}_{1A} = \dot{E}_{A} = \dot{I}^{oc}_{1A} (z^{Gsc}_{1} + z^{Gsc}_{2} + 4z^{Gsc}_{0} + 9z^{Fsc}_{0})$$

or

$$\dot{I}^{oc}_{1A} = \dot{I}^{sc}_{0} = \frac{\dot{E}_{A}}{z^{Gsc}_{1} + z^{Gsc}_{2} + 4z^{Gsc}_{0} + 9z^{Fsc}_{0}} \tag{9-33}$$

The zero-sequence current flowing from the substation M

$$\dot{I}_0^{Msc} = \dot{I}_0^{Gsc} = \dot{I}_0^{oc} = -2\dot{I}_{1A}^{oc}$$

and in compliance with (9-33)

$$\dot{I}_0^{Msc} = \frac{2\dot{E}_A}{z_1^{Gsc} + z_2^{Gsc} + 4z_0^{Gsc} + 9z_0^{Fsc}} \tag{9-34}$$

The zero-sequence current flowing from the substation F

$$\dot{I}_0^{Fsc} = \dot{I}_0^{sc} - \dot{I}_0^{oc}$$

and with (9-33) and (9-34) taken into account

$$\dot{I}_0^{Fsc} = \frac{3\dot{E}_A}{z_1^{Gsc} + z_2^{Gsc} + 4z_0^{Gsc} + 9z_0^{Fsc}} \tag{9-35}$$

It is seen from the above expressions that, when cascade tripping of an earthed phase is used, the zero-sequence currents flowing in the line MN from the substations M and N are far different in value from the currents flowing to the one-phase short circuit on the line MN when the faulty phase of the line is connected from both the substation M and substation N sides.

To consider the effect of the load on the current flows in the phases and on their symmetric components, the impedances z_1^{Fsc} and z_2^{Fsc} and the corresponding load impedances should be placed into the equivalent circuits. This done, the current calculations are made with due consideration to the particular features of the operation being analyzed. The calculation techniques are dealt with in special literature [9-3].

9-2. Types of Discriminating Elements of PARC Devices

The implementation of one-phase ARC devices is possible provided specially designed elements are available that can determine which phase (of the three) is at fault and make the protection system trip this phase. During an PARC cycle the instantaneous protection units responsive to the currents and voltages of zero and backward sequences may malfunction. These protection units must be desensitized or rendered inoperative for the PARC cycle. In the latter case the instantaneous clearing of a line fault is a function of the PARC selectivity (discriminating) elements.

Most simply discriminating elements may be realized on lines supplied at one end.

At the supply end the faulty phase is detected by current relays connected to the phase currents of the line. Use may also be made of undervoltage relays connected to the phase voltages.

Discriminating elements in the form of current relays cannot be used at the receiving end, as in the case of an earth fault, equal currents of zero sequence flow in all three phases. A faulty phase can be detected by the voltage relays connected to the potential transformer of the high-tension busbars of the receiving substation (Fig. 9-6). When a one-phase short circuit occurs on the line, the faulty phase voltage drops and the voltage relay connected to this phase closes its contact to permit the protection system to trip the breaker of the phase

at fault. When two or three voltage relays function simultaneously, this may be the case when two phases are earthing or in the case of a three-phase short circuit, provision should be made to block the output relays of the device so that all three poles of the breaker are tripped.

To selectively detect a faulty phase, cosine type power relays connected into a circuit shown in Fig. 9-7[9-4] may be also used. The current coils of the relays are connected to carry the current $3\dot{I}_0$ and the voltage coils to the voltages of phases A, B and C. The relay contacts are connected so that the protection circuit intended for tripping the breaker of phase A is completed through the tripping contact of the relay connected to the voltage $\dot{U}_{C0}$ and through the make contact of the relay connected to the voltage $\dot{U}_{A0}$.

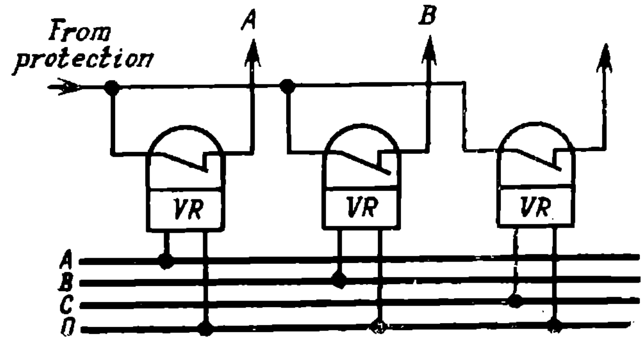


Fig. 9-6. Circuit of faulted phase discriminator with undervoltage relay

The circuit tripping the breaker of phase B is completed through the closing contacts of the relay connected to the voltage $\dot{U}_{B0}$ and the breaking contacts

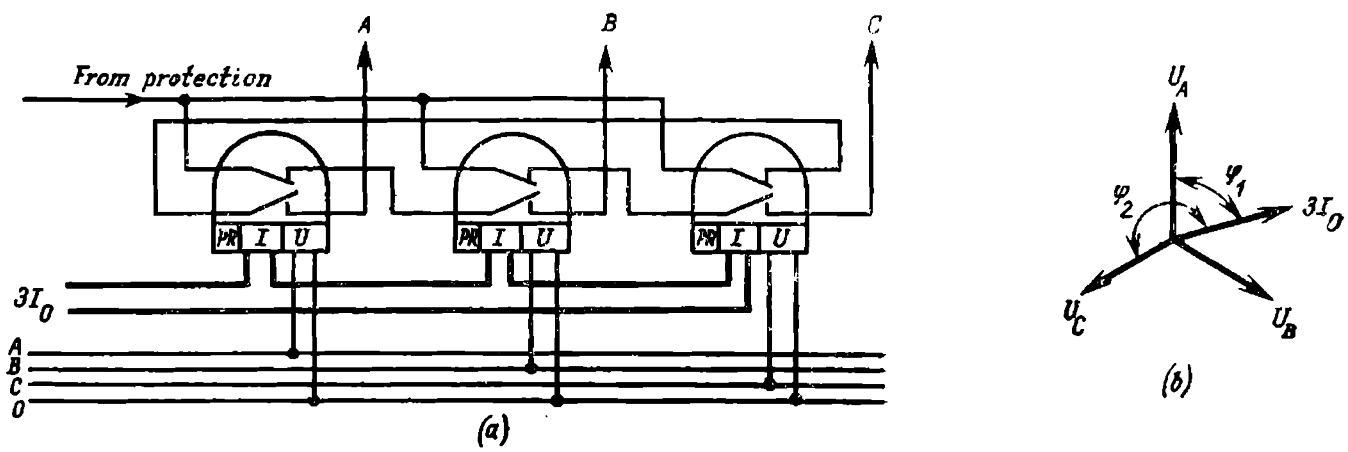


Fig. 9-7. Circuit of faulted phase discriminator with power relay
(a) circuit diagram; (b) diagram of currents and voltages (phase A is earthed; relay PR is a power relay of cosine type)

of the relay connected to the voltage $\dot{U}_{A0}$. The make contacts of the relay connected to the voltage $\dot{U}_{C0}$ and the break contacts of the relay connected to the voltage $\dot{U}_{B0}$ complete the circuit for tripping the breaker of phase C.

It is seen from the vector diagram (9-7b) that in the case of a one-phase short circuit on phase A, the current $3I_0$ makes the first relay function, while the third relay is reliably braked with the effect that the circuit sharply detects

the faulty phase. It is easily seen that in the case of short circuits on the other phases, the discriminating element operates similarly.

At the receiving substations the potential transformers are generally installed at the low-tension side of the power transformer. The discriminating elements with power relays make it possible for them to be supplied from the voltage transformers installed at the delta-connection side of the power transformer which uses an earthed neutral star-to-delta connection. Account is taken of the fact that a certain interphase voltage of the delta side corresponds to a certain phase voltage at the star side. For example, interphase voltages $(-U_{C'A'})$,

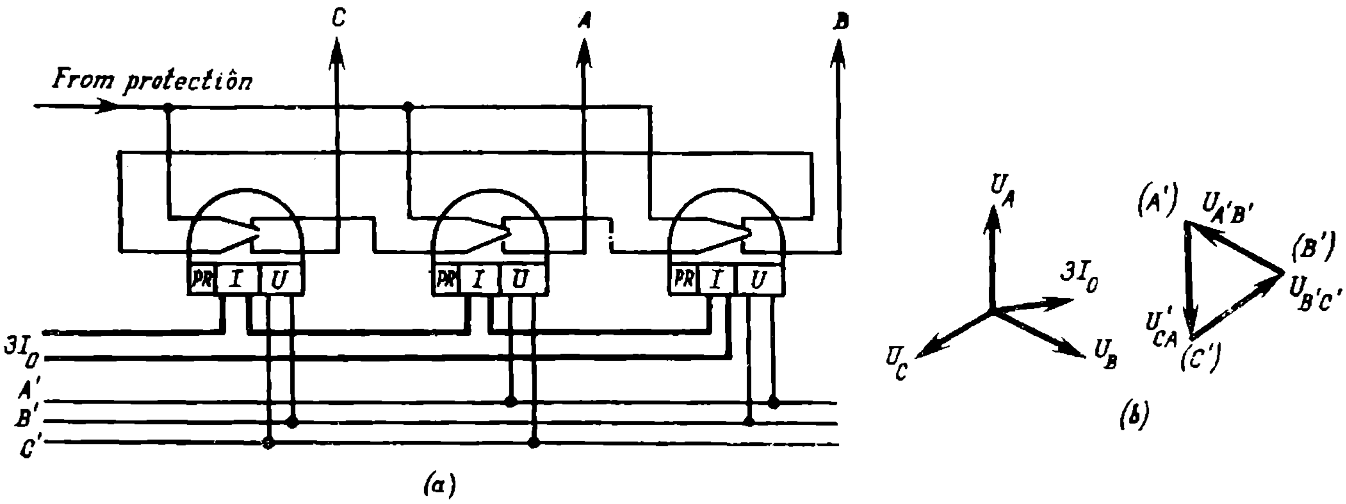


Fig. 9-8. Circuit of phase discriminator with power relay of cosine type when the voltage coils are supplied from the delta side of the power transformer with star-connected windings and delta-connected neutral point
(a) circuit diagram; (b) diagrams of currents and voltages

$(-U_{A'B'})$ and $(-U_{B'C'})$ at the delta side of the power transformer correspond to the phase voltages U_{A0}, U_{B0} and U_{C0} at the star side (Fig. 9-8*b*). The relay (Fig. 9-7*a*) can be connected by the circuit shown in Fig. 9-8*a* to ensure similar discrimination.

Illustrated in Fig. 9-9 is the circuit of a current discriminator for an PARC device installed at the supply end of the line. The current relays *CRA*, *CRB* and *CRC* are current cutoffs connected to the currents of faulty phases with a reach covering the entire transmission line. If a one-phase short circuit occurs, then one current relay functions and closes one of the auxiliary relays *ARA*, *ARB* or *ARC*, which trips the faulty phase and triggers the ARC device. The latter recloses the breaker. In the case of unsuccessful reclosure, the faulty phase is tripped repeatedly and the consumer is supplied from a two-phase and earth circuit. When a two- or three-phase short circuit occurs, the circuit shown in Fig. 9-9 assures the tripping of all three phases with their subsequent automatic reclosure. The tripping is accomplished by the *AR3P* relay which picks up when any two relays of *ARA*, *ARB* and *ARC* function.

With lines supplied from both ends, impedance relays with their phase current and voltage coils energized or directional impedance relays carrying

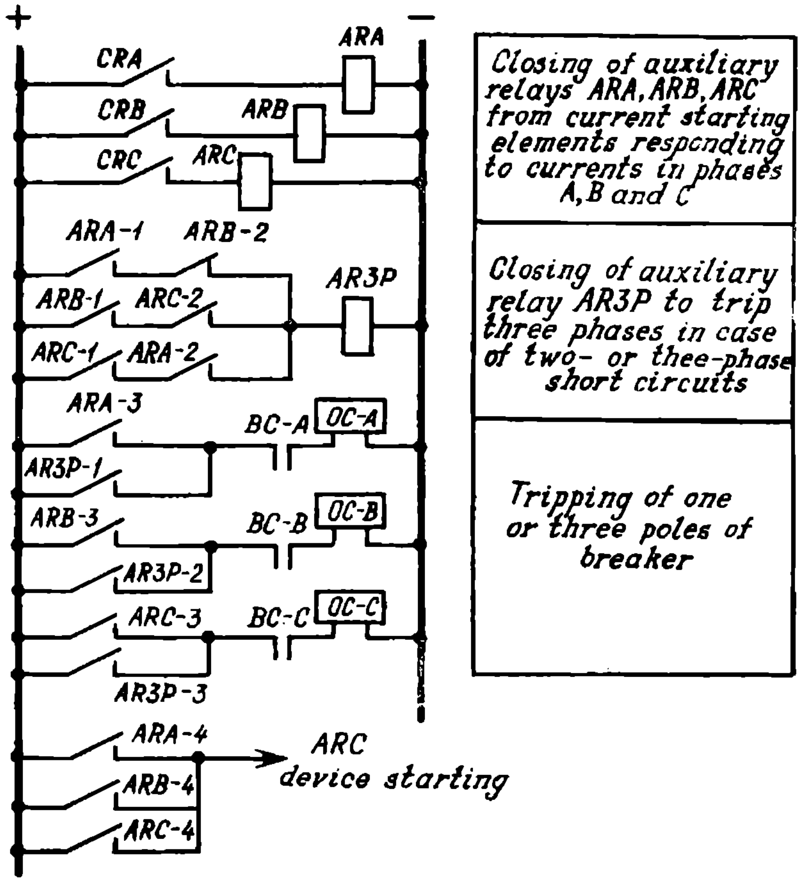


Fig. 9-9. Circuit of current discriminating element of PARC device for lines supplied from one end (supply end)

CRA, CRB, CRC — contacts of current relays; *ARA, ARB, ARC* — auxiliary relays; *AR3P* — auxiliary relay for tripping three phases; *BC-A, BC-B, BC-C* — blocking contacts; *OC-A, OC-B, OC-C* — opening coils

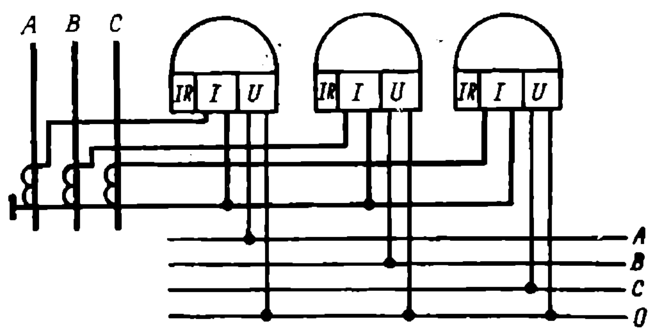


Fig. 9-10. Circuit of PARC device discriminating element employing impedance relay

the current $\dot{I}_r = \dot{I}_{ph} + k\dot{I}_0$ and the voltage of the faulty phase are used as faulty phase discriminators.

The circuit of a discriminator employing an impedance relay is shown in Fig. 9-10. When earth faults occur the discriminator, connected to the current and voltage of the faulty phase, measures the impedance

$$|z_r| = \frac{|\dot{U}_{ph}|}{|\dot{I}_{sc}|} \tag{9-36}$$

When only one phase is earthed the terminal impedance of the relay of the faulty phase

$$z_r = \frac{\dot{I}_1^{Msc} z_1^{Msc} + \dot{I}_2^{Msc} z_2^{Msc} + \dot{I}_0^{Msc} z_0^{Msc}}{\dot{I}_{ph\,sc}^{Msc}}$$

After adding and subtracting $\dot{I}_0^{Msc} z_1^{Msc}$ in the numerator and considering that for transmission lines $z_1^{Msc} = z_2^{Msc}$, we obtain

$$z_r = \frac{z_1^{Msc}(\dot{I}_1^{Msc} + \dot{I}_2^{Msc} + \dot{I}_0^{Msc}) + \dot{I}_0^{Msc}(z_0^{Msc} - z_1^{Msc})}{\dot{I}_{ph}^{Msc}} =$$

$$= \frac{z_1^{Msc}\dot{I}_{ph}^{Msc} + \dot{I}_0^{Msc}(z_0^{Msc} - z_1^{Msc})}{\dot{I}_{ph}^{Msc}} \tag{9-37}$$

Hence

$$z_r = z_1^{Msc} + \frac{\dot{I}_0^{Msc}}{\dot{I}_{ph}^{Msc}}(z_0^{Msc} - z_1^{Msc}) \tag{9-38}$$

is not a constant magnitude and depends on the current ratio $\dot{I}_0^{Msc}/\dot{I}_{ph}^{Msc}$. The relays connected to the voltages of the sound phases measure large impedance values. If the pickup setting of the relay is less than the minimum operating impedance with account taken of its variations due to swings in the PARC cycle, the required discrimination action is obtained.

Discriminating elements made up of impedance relays do not possess a sensitivity sufficient for long transmission lines carrying heavy loads. Under these conditions, better results are produced by the discriminating elements of directional impedance relays connected to the phase voltages and the current $\dot{I}_{ph} + k\dot{I}_0$ (Fig. 9-11).

In accordance with Fig. 9-11 such a relay measures the impedance

$$z_r = \frac{z_1^{Msc}\dot{I}_{ph}^{Msc} + \dot{I}_0^{Msc}(z_0^{Msc} - z_1^{Msc})}{\dot{I}_{ph} + k\dot{I}_0^{Msc}} = z_1^{Msc}\left[\frac{\dot{I}_{ph}^{Msc} + \dot{I}_0 \dfrac{z_0^{Msc} - z_1^{Msc}}{z_1^{Msc}}}{\dot{I}_{ph}^{Msc} + k\dot{I}_0^{Msc}}\right]$$

When

$$k = \frac{z_0^{Msc} - z_1^{Msc}}{z_1^{Msc}} \tag{9-39}$$

$z_r = z_1^{Msc}$, i.e., the relay terminal impedance is proportional to the forward-sequence impedance from the relay to the point of the short circuit. The relay

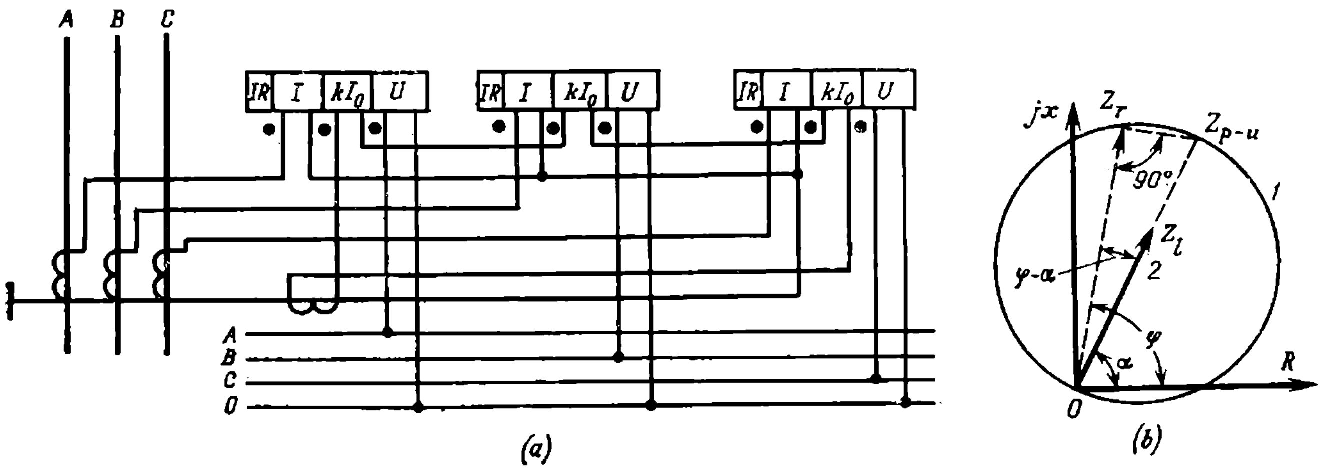


Fig. 9-11. Connection diagram of PARC device discriminating element employing directional impedance relays carrying $\dot{U}_r = \dot{U}_{ph}$ and $\dot{I}_r = \dot{I}_{ph} + k\dot{I}_0$

(a) circuit diagram; (b) characteristics shown as coordinates R, jX; 1 — characteristic of faulted phase relay; 2 — characteristic of the line whose impedance is z_l

operates, if this impedance is

$$|z_r| = \left| \frac{\dot{U}_{ph}}{\dot{I}_{ph} + k\dot{I}_0} \right| \leqslant z_{p\text{-}u} \cos(\varphi - \alpha) \tag{9.40}$$

where $z_{p\text{-}u}$ = relay pick-up setting equal to the diameter of the characteristic circle as determined by the R and jX axes (Fig. 9-11*b*)

φ = angle between the current $\dot{I}_{ph} + k\dot{I}_0$ and the voltage $\dot{U}_{ph}$ impressed upon the relay

α = relay internal angle determining the maximum sensitivity region. The angle α is usually taken as equal to the angle of the line under protection, φ_l = 60 to 80 degrees

That the points determining the location of the end of vector z_r (by the axes R and jx) geometrically form a circle having a diameter z_{p-u} is easily seen from Fig. 9-11*b* and expression (9-40).

The angle Oz_rz_{p-u} in the triangle Oz_rz_{p-u} is a right angle based on the side z_{p-u}. Consequently the end of the vector z_r slides along a certain curve so that at any values of $\cos(\varphi - \alpha)$ the triangle remains a right-angle triangle. This is possible only if the geometrical location of the points described by the end of vector z_r is a circle with diameter z_{p-u}.

To ensure the discriminating action of the relay in the case of short circuits through an arc near the installation place of PARC device, the characteristic of a directional impedance relay and its type are sometimes selected so that the zone of its action covers the substation busbars with a 10 to 15 per cent margin of the line length (the characteristic of the relay is displaced by this value).

Circuits of the PARC device employing discriminating elements made up of impedance relays are complicated and have many contacts. The circuit becomes complicated because, in addition to its duties of detecting, tripping and reclosing a faulty phase, it must also:

Promote the disconnection of the three phases in the case of interphase short circuits, persisting earth faults and failure of the discriminating elements.

Prevent the operation of protection units which can malfunction during the PARC cycle.

Protect the line against an earth fault, should such a fault occur during the PARC cycle.

Protect the lines (though not selectively), when the lines are changed over to prolonged operation under the two phases—earth conditions.

The wide practical use of such devices in power systems is mainly hindered by the complexity of the PARC device circuits. Simpler requirements for the protection and automatic devices often call for replacement of one-phase ARC devices with three-phase ones when it is permitted under the operating conditions of the power system.

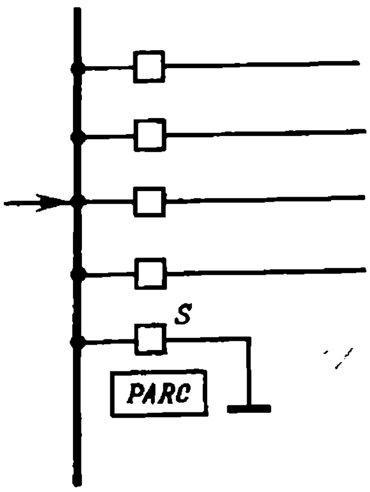


Fig. 9-12. Group PARC principle effected through bypassing a one-phase short circuit with a breaker on the faulted phase

The circuit in Fig. 9-12 shows the group principle underlying the PARC device which is applied in some power systems abroad. When an earth fault occurs on any of the transmission lines run from the substation busbars, the protection of the faulty line functions and, after detecting the faulty phase, sends a tripping pulse to the similar phase of breaker S. The line, in this case, remains connected. After the similar phase of the breaker has closed, the short circuit is bypassed. If a short circuit is effected through an arc the arc becomes extinguished, 0.2 to 0.3 s later the breaker opens to restore the normal power supply.

If the cause of the short circuit persists, then, after tripping the phase of breaker S, the short circuit on the faulty line makes the protection system function to disconnect the line through the three phases. This time, however, breaker S does not close.

Instead of a breaker it was proposed that a jet of conductive liquid fired from a hydraulic gun could be used to bypass the faulty phase. The principle disadvantage of this method is that the short-circuit tripping time becomes prolonged and the short-circuit point is transferred to the busbars. These circumstances make the accomplishment of ARC operations by this method for interphase short circuits very difficult.

9-3. PARC Circuit

Shown in Fig. 9-13 is a circuit of a PARC-3 device developed at the All-Union Scientific Research Institute of Power Engineering for 220-kV lines. The device operates as follows [9-5].

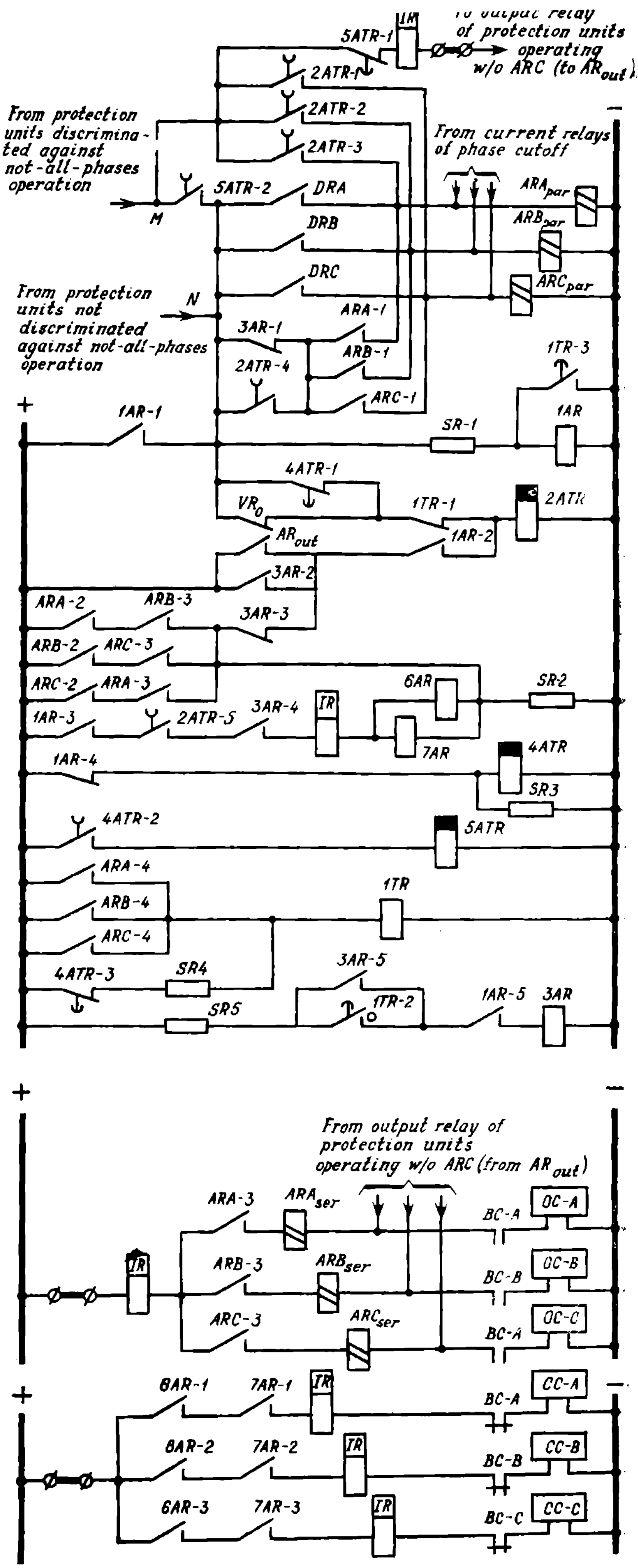


Fig. 9-13. Circuit diagram of PARC-3 device

DRA, *DRB*, *DRC* — contacts of discriminating relays installed on phases *A*, *B*, *C*; *ARA*, *ARB*, *ARC*, *1AR*, *3AR* — auxiliary relay, type КДР-1; *2ATR*, *4ATR*, *5ATR* — relay with delayed dropout; *6AR* and *7AR* — auxiliary relays; *1TR* — time relay; VR_0 — relay of zero-sequence voltage; *BC-A*, *BC-B*, *BC-C* — blocking contacts of breakers; *IR* — indicating relay; *SR* — series resistor

When a one-phase short circuit occurs, relay VR_0 functions and the relay *1AR* picks up due to the protection action. This relay holds itself closed with the contact *1AR-1* until the final contact of the time relay (*1TR-3*) closes. The device then automatically resets. Contact *1AR-4* opens the circuit of relay *4ATR*. Contacts *1AR-2*, *1AR-3* and *1AR-5* prepare the circuits of the coils of relays *2ATR*, *6AR*, *7AR* and *3AR*. The discriminating elements (relays) *DRA*, *DRB* and *DRC* detect the faulty phase and close the parallel coils of relays ARA_{par}, ARB_{par}, and ARC_{par}. Relays *ARA*, *ARB* and *ARC* function. These relays close the contacts and hold themselves closed through the series (holding) coil and trip the faulty phase.

Contacts *ARA-4*, *ARB-4* and *ARC-4* close the relay *1TR*, while contacts *ARA-1*, *ARB-1* and *ARC-1* additionally hold the relay closed through the parallel coil. The self-holding circuit is opened after operation of relay *3AR* and opening of the break contact *3AR-1*. Such connection ensures disconnection of the three phases in case the fault affects the other phases up to the moment the sliding contact of the time relay operates.

The *5ATR* relay is triggered from the contact *4ATR-2* of relay *4ATR*. These relays are reset delayed. One of the contacts of relay *4ATR* performs the "pickup" of relay *1VR* over the circuit *4ATR-3—SR4*. The total delay time of the relays *5ATR* and *4ATR* (about 0.5 s) is sufficient to allow the reset of the protection units discriminated against uncomplete phase operations when the faulty phase of the line is tripped by the cascade method. The circuit of these protection units is controlled by contact *5ATR-2* which separates the circuits of the protection units isolated and not isolated against uncomplete phase operations and makes it possible for the protection units discriminated against the PARC cycle to accomplish tripping operations apart from the contacts of the discriminators.

The relay *3AR* functions after the sliding contact of relay *1VR* has closed. The relay is self-held until the circuit is opened by the contacts of *1AR*, i.e., until the circuit is reset. The relay *3AR* closes the *2ATR* relay through the contact *1AR-2* and with the contact *3AR-1* opens the self-holding circuit of the tripping relays in order to obtain the possible subsequent reclosure of the breaker by the automatic controls. The contacts *2ATR-1*, *2ATR-2* and *2ATR-3* of relay *2ATR* switch over the circuit to trip the three phases and its contact *2ATR-4* restores the self-holding circuit of the relays *ARA*, *ARB* and *ARC*.

The three phases may be tripped also through relay AR_{out} after the operation of relay *5ATR* (this circuit is a back-up protection intended to operate if *ARA*, *ARB* and *ARC* fail).

The relays *6AR* and *7AR* close the line in the time determined by the setting of sliding contact *1TR-2* of time relay *1TR*. The closing circuit is excited through the two series-connected contacts of relays *6AR* and *7AR* to eliminate possible misoperation of the PARC device in the case of a baked contact.

When a fault occurs on the other phases the output relays are blocked and the ARC operation is prohibited by contacts *ARA*, *ARB* and *ARC* through bypassing the coils of *6AR* and *7AR*. The three phases of the breaker are disconnected from the AR_{out} relay.

In the case of two- and three-phase short circuits all three phases immediately trip without reclosure, as the relay *2ATR* is closed by the protection units through the breaking contact of relay VR_0, while the relays *6AR* and *7AR* are blocked in order to block a one-phase ARC and trip the three phases.

A combined device for one-phase and three-phase ARC operations has been also developed. This device performs phase-after-phase automatic reclosure when one phase of the transmission line is tripped, and a three-phase automatic reclosure when the three phases are tripped.

9-4. Use of TPARC Device of Double-Shot Type and Pole-After-Pole Isolators in Place of a PARC Device on Lines Supplied at One End

On lines supplied at one end, the PARC device requires a breaker at the receiving end. With the aim of saving equipment and simplifying the secondary circuits, the lines supplied at one end can be equipped with double-shot TPARC devices and pole-after-pole isolators controlled either manually or remotely in place of a PARC device. In this case, the receiving end is not furnished with a breaker and, to facilitate the change-over to the two phases—earth operation in case of an unsuccessful two-shot automatic reclosure and persisting fault of one phase, a signalling unit is installed to indicate the faulty phase [9-6].

With such a power supply circuit, the change-over to the two phases—earth operation is performed with an interruption to the power supply, this is tolerable as, on the one hand, cases like this occur very seldom and, on the other hand, the use of one-end supply allows possible interruptions to the power supply for a certain period of time.

The use of a three-phase ARC device also promotes automatic reclosures of the busbars, which cannot happen when a PARC device is installed on the line. In the case of a persisting one-phase short circuit on the line, the substation is deenergized. This circumstance should be taken into account when selecting a circuit to control the isolators and, if the substation is furnished with remote-control means, a power supply circuit for them. The most practicable is the use of a buffer d.c. battery or an operative current source automatically changed to a supply from a small engine (an automobile engine, for example) which starts when the substation is deenergized.

For the lines in service which are furnished with a breaker at the receiving end (one not dismantled), the reference [9-1] specifies that pole-after-pole automatic reclosure must be accomplished with an automatic change to two-phase operation when the PARC operation is unsuccessful. To speed up the power supply to the load, when a fault persists on one phase of the line, the preliminary work outlined below must be done.

(a) It is necessary to ascertain (with due consideration for the importance of the transmission system, the possibility of persisting short circuits because of sleet, defective wood, defective insulators, etc.) or whether it is profitable to prepare the lines for two-phase operation when they work under one-end

supply conditions, while other lines are under repair. For this, the line must be tested.

(b) Calculations and tests must be carried out to determine the maximum power that can be carried by two phases of the line according to their effect on the communication lines, asymmetry in the generators, and the like.

If the tests show that two-phase working causes unwanted interference with the operation of the communication systems the permitted conditions for communication breaks during two-phase operation and the advisability of taking measures to limit the power transferred by the line must be considered. This also includes the unearthing of some transformer neutrals in order to limit the zero-sequence currents in two-phase operation and the installation of drainage coils or other devices on the communication lines to lessen the interference.

(c) Instructions on the line transfer to two-phase working under emergency conditions must be developed and issued to station personnel.

(d) To enable the transfer of a given line to two-phase working without delay for preparation, for this protective relaying and automatic devices must be used on the line and other elements of the power system.

9-5. Conclusions

1. Pole-after-pole (one-phase) ARC has an advantage over three-phase automatic reclosure in that the electrical connection is not completely disturbed in the PARC cycle. Because of this, for single tie lines connecting the power system lines, the operating time of the PARC devices, as dictated by the stability requirements, may be far longer than that for the three-phase ARC devices. In certain cases the system operation may be continued through two phases and earth. Limitations to the use of PARC devices are caused by their complexity, the necessity of controlling each phase of the breakers and the more complicated protective relaying.
2. To improve the operation of ARC devices, it is good practice to combine the operation of PARC and TPARC devices.
3. One-phase ARC for single lines supplied at one end needs the installation of breakers having control for each phase both at the sending and receiving ends. When no breaker is used from the receiving end, the sending end must be furnished with a TPARC device, preferably of two-shot action, and pole-after-pole isolators (from the sending and receiving ends), in order to promote the most rapid change-over to supply through two phases and earth when one phase is at fault. To change over to such operation, preparatory work must be done and operators given instructions.
4. For lines supplied at one end, the discriminating elements of the PARC device are simply accomplished from the supply side through the use of current or voltage relays or by means of directional power relays from the receiving side.
5. With single intersystem tie lines and single lines connecting a power station to the power system, the discriminating elements of the PARC device are

best made up of impedance relays or with the aid of directional impedance relays connected to the phase voltage and current $\dot{I}_{ph} + k\dot{I}_0$.

6. When a PARC device is installed on the line, one must take into account the fact that a breaker may trip the phase from one side both when this phase is at an earth fault and when it is not. Changes in the zero-sequence current should not cause malfunction of the protective relaying, starting and discriminating elements of the PARC devices.

9-6. Review Questions

1. Describe the advantages and disadvantages of PARC as compared with HSARC and asynchronous ARC of the tie lines.
2. Substantiate the use of distance relays for making up the discriminating elements of PARC devices. What are the desirable characteristics of these relays?
3. May three directional power relays connected to zero-sequence current and phase voltages be installed as discriminating elements at the supply end of a line supplied from one end?
4. What are the peculiarities of two phases—earth operation of a receiving substation?
5. The operating current of earth-fault protection responsive to the $3I_0$ current is chosen as needed for discrimination against an unbalance current in the case of an external short circuit and equals $0.3I_n$. Must the operating setting of the protection be changed, if the line is switched over to perform prolonged operation under the two phases — earth conditions?
6. Will the protection connected to zero-sequence current from the supply substation side respond to interphase short circuits at the secondary side of the power transformer of the receiving substation if the transformer group consists of single-phase transformers with their windings being star-delta connected under the conditions when one of the transformer group phases is disconnected because of a fault?
7. Why does the operation of PARC devices influence the performance of overhead communication lines? Give reasons.
8. How is simultaneous three-phase tripping obtained, in the case of interphase short circuits and manual tripping, when the breakers are controlled separately for each phase?
9. Trace the interaction of the individual relays of the PARC device circuit shown in Fig. 9-13. Describe the sequence of operations when a one-phase short circuit occurs on the line. How is the single-shot performance of the PARC devices ensured?
10. Can the pole-after-pole automatic reclosure devices of lines accomplish automatic reclosure of the busbars which are at fault?
11. Compare the operation of electrical circuits with a dead-earthed neutral and pole-after-pole ARC devices on the lines with the operation of circuits having their neutral earthed through an arc extinguishing coil. Is it practicable to use pole-after-pole reclosures in the compensated (reactor earthed) circuits?
12. Why is it that most of the faults on overhead transmission lines are one-phase faults to earth?
13. 220-kV lines are furnished with PARC devices. Is it practicable to install TPARC devices on these lines too?
14. A 110-kV line of a system with a dead-earthed neutral is furnished with PARC and TPARC devices. How can the action of the TPARC device be prohibited during operation of the PARC device when the former is connected into the circuit shown in Fig. 8-4?
15. A dead ending transmission line is furnished with PARC devices (Fig. 9-5). A one-phase short circuit has occurred on the phase A at point SC. Determine the difference between the values of the zero-sequence currents flowing in the line MN under conditions when all three phases of the breaker are closed at both ends of the line and when the faulty phase is being disconnected in the cascade manner (the phase being tripped from the side of substation M and not from the side of substation N). The load current of the receiving substation is not taken into account.

Solution. *A one-phase short circuit at point SC. The breakers of the three phases are closed both from the side of substation M and from the side of substation N.* In compliance with (9-9) the zero-sequence current in the point of short circuit (at point SC) is

$$\dot{I}_0^{sc} = \frac{\dot{E}_{ph}}{\Sigma z_1^{sc} + \Sigma z_2^{sc} + \Sigma z_0^{sc}} \tag{9-41}$$

where Σz_1^{sc}, Σz_2^{sc} and Σz_0^{sc} are the forward-, backward- and zero-sequence impedances reduced to the point of short circuit.

As the effect of the receiving substation load is neglected and no generation is available from the substation F, taken into account for the section F-SC is only the zero-sequence impedance, thus

$$\dot{I}_0^{sc} = \frac{\dot{E}_{ph}}{z_1^{Gsc} + z_2^{Gsc} + \dfrac{z_0^{Gsc} z_0^{Fsc}}{z_0^{Gsc} + z_0^{Fsc}}} \tag{9-42}$$

The zero-sequence current flowing in the section M-SC is

$$\dot{I}_0^{Msc} = \dot{I}_0^{Gsc} = \dot{I}_0^{sc} \frac{\Sigma z_0^{sc}}{z_0^{Gsc}} \tag{9-43}$$

$$\dot{I}_0^{Msc} = \frac{\dot{E}_A}{z_1^{Gsc} + z_2^{Gsc} + \dfrac{z_0^{Gsc} z_0^{Fsc}}{z_0^{Gsc} + z_0^{Fsc}}} \times \frac{z_0^{Fsc}}{z_0^{Gsc} + z_0^{Fsc}} \tag{9-44}$$

A cascade tripping of a faulty phase. Phase A is tripped from the side of substation M. From the side of substation N all the three phases remain closed (Fig. 9-5).

After tripping a phase from the side of substation N the zero-sequence current at the point of short circuit is determined by expression (9-33). In compliance with (9-34) the value of the current lightly flowing from substation M

$$\dot{I}_0^{Msc} = \frac{2\dot{E}_A}{z_1^{Gsc} + z_2^{Gsc} + 4z_0^{Gsc} + 9z_0^{Fsc}}$$

To quantitatively evaluate the changes in the current, assume that $z_0^{Fsc} = 4z_0^{Gsc}$ and $z_1^{Gsc} = z_2^{Gsc} = 0.1\ z_0^{Fsc}$.

After the faulty phase is tripped from the side of the supply substation, with the above-mentioned relationships, the current in the place of fault drops about 25 times, while the zero-sequence current flowing in the line from the substation M decreases about 10 times. An abrupt drop of the current at the place of short circuit may extinguish the arc and result in a successful pole-after-pole reclosure, even when the phase is tripped from one side only.

If the faulty phase fails to be tripped from the side of substation N and the short-circuit arc persists, the back-up zero-sequence current protection installed on the line from the side of substation M must trip all three phases of the breaker from the side of substation M. Therefore, the back-up protection must be checked for sensitivity to see whether it suits the operating conditions in which a phase at earth fault is tripped at one end.

A failure of the back-up protection at the supply end may cause the "suspension" of a one-phase short circuit.

Chapter Ten

THREE-PHASE AUTOMATIC RECLOSURE OF TRANSFORMERS AND BUSBARS

10-1. General

Successful automatic reclosures are possible not only after clearing short circuits on transmission lines but also after tripping short circuits on the busbars of substations and terminals of power transformers. Moreover, the automatic reclosures of these connections sometimes correct misoperation of the protective relaying devices and erroneous actions of attending personnel.

The best results from the use of ARC of busbars and transformers are obtained at substations in areas with badly polluted atmospheres from chemical and metallurgical plants (generally resulting in unstable insulator flash-overs) and also at unattended substations not furnished with remote control.

According to collected statistics [10-1] successful automatic reclosures average 64.8 per cent for busbars and 60 per cent for transformers (see Table 8-2).

The term "busbar ARC" from this point on means the automatic reclosure of one or several breakers tripped by the action of the output relay of special busbar protection (differential protection or a back-up device that operates if the breakers fail). The term "transformer ARC" means, henceforth, the automatic reclosure of one or several transformer breakers which are tripped by the action of one or several protection units placed in the circuit of the given transformer. Thus, if a short circuit occurred on the busbars and it was cleared through the action of the differential busbar protection by a breaker placed in the circuit of a step-up transformer, the reclosure of this breaker with the energizing of these busbars is considered as busbar ARC. If this very same short circuit is isolated by the same breaker through the action of the protection device connected into the circuit of the transformer (an example is a back-up overcurrent protection), breaker ARC is considered as transformer ARC.

The ARC devices of busbars perform different functions. Automatic testing of the busbar insulation after the busbars are deenergized is most easy. Somewhat more complicated is the trying out of the busbars and the power supply to the consumers deenergized at the time when the busbars are tripped. Still more difficult is the automatic restoration of the normal substation circuit after finding that the busbars are in good condition.

The most difficult is the automatic restoration of the normal primary connection circuit of the power station.

The ARC devices of power transformers are particularly effective for cases of one-end load, feeding from these transformers. As the back-up protection of

the transformers is brought into action when short circuits occur on the L.T. busbars (often no differential protection is used to protect these busbars) and also when short circuits on the outgoing lines cannot be cleared, successful ARC restores the power supply to the entire area.

Installation of ARC devices on the transformers of a distribution network is very important (at substations supplying drilling derricks). Infrequently a current protection, having sensitivity sufficient to ensure its response to short circuits at the end of the line running to the consumer is not isolated against the starting currents of the asynchronous motors driving the derrick mechanisms when they are started simultaneously. Reclosing of a transformer tripped due to overload allows the consumers to restore the production process in the preassigned starting sequence.

The use of busbar and transformer ARC is regarded as mandatory [10-2]. Rejection of their use must be substantiated each time. When busbar and transformer ARC devices fail to operate or when they are taken out of service (to undergo repair, for instance) station personnel should immediately reclose the corresponding breakers by means of the remote-control system or (for oil breakers only) by hand on site. Exceptions are when an intolerable current surge occurs due to asynchronous voltage.

For transformers tripped by one of the protections against internal troubles and when no observable symptoms of damage are present, one reclosure is permitted, if the transformer tripping suspends the consumer's supply [10-2].

Development of electrical power systems in rural areas with their connection through fuses, and the replacement of protective relaying devices and breakers with fuses in H.T. circuits, bring about the problem of devising a device capable of automatically renewing blown fuses with good ones within a specified period of time.

Good results are produced by the use of ARC devices on the lines of railway traction systems. These devices may be widely applied in 110-220-380-volt installations, since daily experience indicate that the causes of a short circuit are most often self-eliminated after deenergizing. In a series of cases power plants and substations use automatic protection circuit breakers to control the condition of the operating current circuits at 48-220 volts and the potential transformers circuits. It is good practice to have circuit breakers of a design which assures ARC operation.

When short circuits occur in H.T. circuits blown fuses often happen in the communication and remote-control circuits due to the effects of induced currents. The ARC devices renewing blown fuses within a time greater than the dead time and the ARC cycle of H.T. lines, enables the channel to be quickly reestablished and ensure the operation of communication and remote-control devices.

The principles underlying ARC operations on the substation busbars, used in a series of power systems, [10-3 and 10-4] and ARC operations on the transformers are described in the next section.

10-2. Automatic Testing of Busbars for Insulation

When the differential protection of the busbars operates an action prohibiting signal, sent simultaneously with the tripping control pulse to the connection breakers, is applied to all ARC devices of these connections except for the connection link used in the insulation testing. The breaker of this link performs an automatic reclosure within the time determined by the ARC device. Since the ARC devices on the other breakers are rendered inoperative, there is no risk of asynchronous connection. In the case of successful automatic reclosure of the busbars, the normal connections of the substation are reestablished by attending personnel either manually or by means of remote-control devices.

The choice of a breaker intended for insulation testing must meet the requirement of keeping the effect of a voltage drop on the working elements of the power system as small as practicable, when the reclosure is made to a persisting short circuit.

After the operation of the busbar differential protection and the action of the ARC device reclosing the breaker of the connection link through which the insulation testing is carried out, the instantaneous sensitive protection must be put into operation. This protection is required because the value of the short-circuit current in the line used to test the busbars is generally far less than the full short-circuit current, occurring with a fault on the busbars when all the connections are closed for normal performance.

The above-mentioned protection is not discriminatory. However, it may be rendered inoperative by operators only after recovery of the substation circuit and normal sensitivity of the busbar protection.

It should be taken into account, however, that a nondiscriminatory sensitive protection may function from the load currents during the operation on reestablishing normal connections of the substation. Therefore, the protection must be discriminated against such currents. For example, it must have voltage blocking or be responsive to the backward- and zero-sequence components with isolation against nonsimultaneous closing of the breaker phases.

Simplicity is obtained by choosing the testing connection link so that a short circuit on the busbars promotes the operation of the busbar differential protection or the functioning of the protection at the opposite end of the line. In these instances nondiscriminatory sensitive protection is not required.

If the substation is supplied from two or more lines, the testing may be performed from two lines. To this end, no prohibiting pulse is fed to the ARC devices of the breakers used by these lines during the operation of the differential protection. In order to ease the load on the storage battery the ARC devices must have different pickup settings. This type of testing provides two-shot automatic reclosure of the busbars in the case of a persisting short circuit. No asynchronous connection is permitted or checks must be made to see whether it can be used.

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10-3. Power Supply to Consumers After Tripping of Busbars and Automatic Reestablishing of Substation Connections

If the tripping of the busbars, being at a short-circuit fault, interrupts the power supply to consumers, then successful automatic reclosure of the busbars must ensure reestablishment of the voltage across the consumer terminals. To achieve this object, when the busbars are at a short circuit, the differential protection must only trip the supply connections, while the connection supplying power from these busbars to the consumers must remain switched on. The

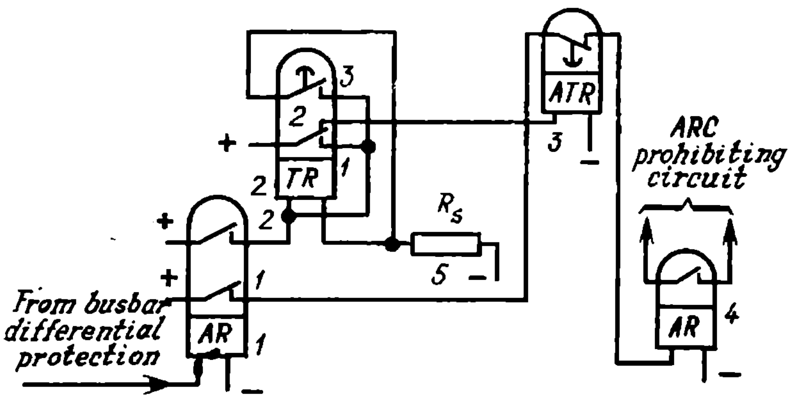

Fig. 10-1. Discriminating prohibition of automatic reclosing of terminations when the busbar differential protection repeats its operation

sensitive protection which operates during insulation testing must be discriminated against load currents. The operating time of the ARC device employed by the breaker through which the testing is performed should be sufficient to transfer the consumers' synchronous load, if any, to operation without excitation or trip it by the instant the voltage is applied to the busbars.

The reestablishment of normal connections of the substation after the operation of the busbar differential protection is by means of the ARC devices installed on the breakers of the lines and transformers [10-3]. During the first functioning of the busbar differential protection no pulse to prohibit the operation of the termination ARC devices is given. The first to close is the termination whose ARC device has the smallest time setting.

If the automatic reclosure is successful, no prohibiting pulses are fed to the other terminations and, if it is unsuccessful, the differential protection of the busbars repeats its operation to prohibit automatic reclosures of the other terminations and trips the closed breaker. The sensitivity of the differential protection should be in this case sufficient to provide its reliable operation in the event of reclosure to a persisting short circuit on the first termination.

The principle underlying the ARC prohibition circuit is clear from Figs 10-1 and 10-2. When the busbar differential protection operates for the first time, the relay *1AR* (Fig. 10-1) functions. Contact *1AR-1* prepares the circuit to close the relay *4AR*. This circuit is broken by the contact of relay *3ATR* whose reset time is about 0.5 s. As contact *1AR-2* is closed it closes relay *2TR*. The latter functions and its instantaneous contact *2TR-2* opens the circuit of relay

3ATR and holds itself closed with its contact *2TR-1* until contact *2TR-3* closes. After the operation of the busbar differential protection the busbars become deenergized and relay *1AR* resets before the contact of relay *3ATR* has closed. Relay *4AR*, the contacts of which prohibit ARC operation on the other terminations, is inoperative. The breaker whose ARC time is shortest recloses.

If the short circuit on the busbars has eliminated itself the ARC devices of the other terminations operate in sequence and restore the initial connections

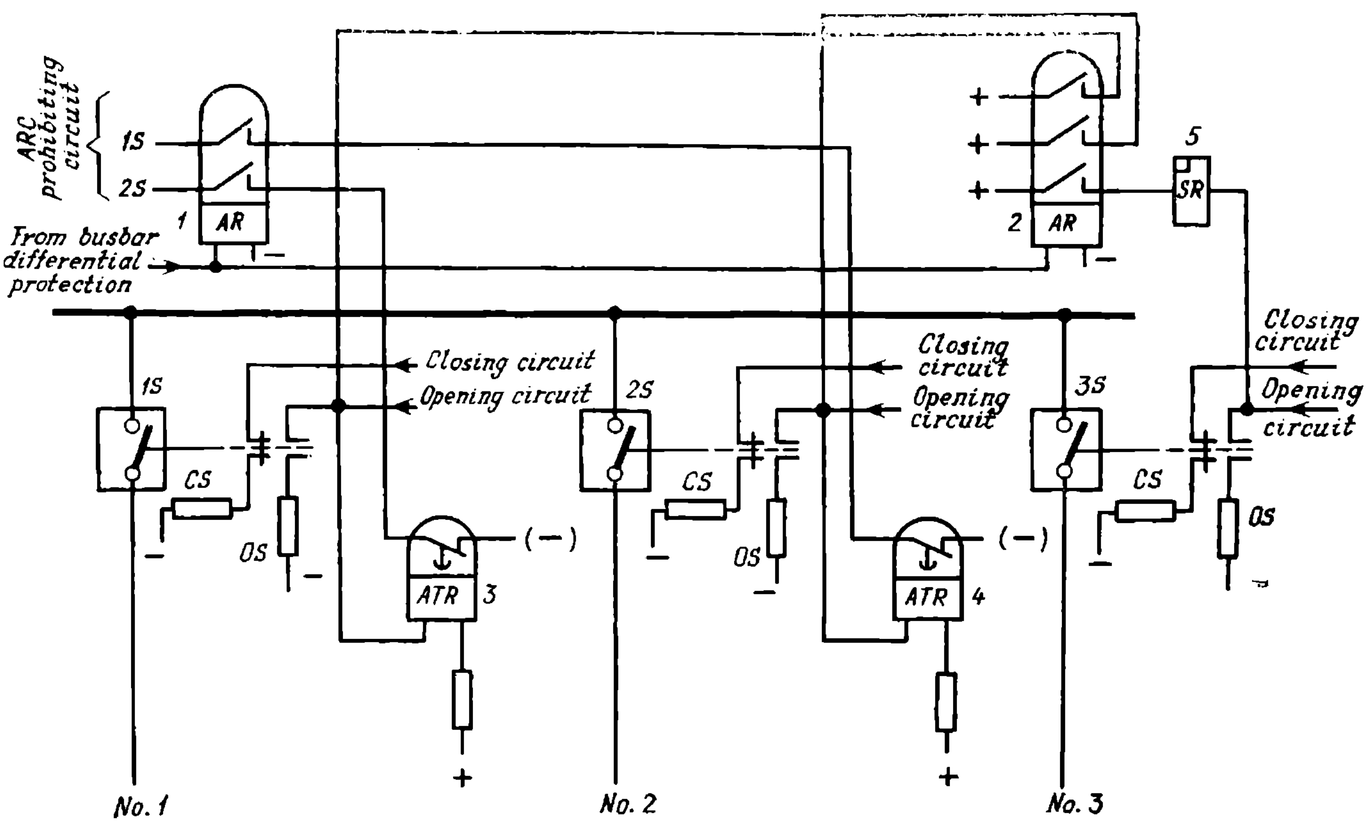

Fig. 10-2. Decentralized prohibition of automatic reclosing of terminations when the busbar differential protection repeats its operation

of the substations. If the short circuit on the busbars persists, the busbar differential protection repeats its operation, contact *1AR-1* closes and, as by this time the contact of relay *3ATR* is closed (this relay was deenergized after the first operation of the busbar differential protection) the relay *4AR* functions. The contacts of relay *4AR* make the circuit and prohibit ARC of all terminations. The device resets after the contact *2TR-3* has closed. The operating time of this contact must be greater than the time of reclosure from the ARC device of the first termination, i.e., it should be equal to the sum of the operating time of the ARC device, the breaker, the busbar differential protection, the fault clearing time by the breaker, and the margin time.

If during testing the sensitivity of the main set of the differential protection is insufficient, the time relay *TR* (or an auxiliary relay) must introduce the sensitive protection to trip the busbars in the case of a persisting short circuit,

and connect its circuit to the relay *4AR* through the contact of relay *3ATR*.

When the differential protection of the busbars operates the circuit shown in Fig. 10-1 produces centralized prohibition of ARC of the terminations.

Fig. 10-2 illustrates a circuit of the ARC decentralized prohibition (proposed by V.R. Mustafin, Chelyabenergo). When the busbar differential protection functions relays *1* and *2* close. The latter trips the supply terminations. The former (relay *1*) "prohibits" the ARC operations. The prohibiting circuit to the ARC device of termination No. 3 may not be present, as the automatic reclosure of the breaker (switch) *3S* is performed first of all*. The prohibiting circuits to the breakers *1S* and *2S* which are planned to complete the circuit, can be closed only after the testing reveals defective busbar insulation in the repeated operation of the differential protection (in case of unsuccessful ARC by the breaker *3S*, the ARC prohibiting circuits of breakers *1S* and *2S* will be closed by the contacts of relay *1AR*. The ARC time settings of these breakers are greater than the ARC time setting of the breaker *3S*).

If asynchronous connections of the lines or transformers are likely to occur during the switching over of the substation circuit, it is useful to furnish the termination breakers with ARC devices using synchronism seizing circuits while the breaker which closes first to check the busbars for conditions, with an ARC device capable of no-voltage detection. AARC devices can be installed under conditions allowing asynchronous connections.

10-4. Automatic Reestablishing of Power Station Connections

Reference [10-4] describes busbar ARC circuits with recovery of the initial, before-fault, conditions. These circuits are applied at several power stations of the Dneprenergo system. The circuits used at the power stations prevent impermissible asynchronous (including two-phase) generator connections.

A centralized unit prohibiting busbar ARC operations is provided. This unit prevents busbar ARC operations in the following cases:

When the busbars remain under voltage after the time specified for their disconnection.

When a short circuit of busbars persists due to a failure of the breaker at one of faulty phase terminations.

When the immediate automatic reclosure is unsuccessful.

When the back-up device of the breaker functions after a failure of the breaker of an autotransformer (transformer, generator-transformer unit) and after its damage.

To improve the sensitivity of the busbar differential protection use is made of an auxiliary protective element having an operating current which is not

* The ARC prohibiting circuit of the breaker of termination No. 3 can be made in the same way as for the breakers *1S* and *2S*. ARC of the breaker *3S* will not be prohibited, as it is the first to be closed by the ARC device (the operating time of ARC device No. 3 is less than that of ARC No. 1 and ARC No. 2). The busbars are deenergized and, thus, the contacts of relay *1AR* are open.

discriminated against unbalance currents from external faults and hunting. This element operates longer than the complete ARC cycle.

The resulting protective and ARC circuit is a relatively complicated one. This is why, as duty personnel are always present at the power station, the problem of automatic reestablishing of the normal connections after the operation of busbar differential protection should be solved with regard to the local conditions and the unwanted complexity of such an important system as the busbar protection. In particular, in many cases automatic connection of the outgoing lines only is necessary, as the duty personnel can be responsible for the subsequent closure of the generators and the generator-transformer units.

10-5. Three-Phase ARC of Transformers

The ARC devices of transformers are intended to recover the power supply after emergency tripping of a feeding transformer for any cause other than internal damage. Automatic reclosures are accomplished by using devices similar to those installed on transmission line breakers. When selecting the circuit of an ARC device, attention must be paid to the operating conditions of the transformer (autotransformer). If the power supply to the transformer is from one side or if it is synchronously supplied from two sides (an example is a three-winding transformer supplied from the 110 and 35-kV sides) or when asynchronous automatic reclosures are allowed, the same type ARC devices are used as on the lines supplied at one end. When it is necessary to sustain the synchronism of the power system parts being paralleled by the breaker in the transformer circuit, the same ARC circuits are used as for the lines of ring systems having more than one points of supply, or for single lines connecting two parts of a power system (see Chapter 8).

The ARC devices of transformers differ mainly in the starting and blocking methods.

Starting of an ARC device, when the main or back-up protection device on the transformer functions, promotes its automatic reclosure whatever the fault (internal faults included). A disadvantage here is that the faulty transformer may reclose with the risk of additional damage. This method may find its applications where use is made of quick-action protection units or where provision is made for speeding up the action of the back-up protection units after the operation of the ARC devices.

ARC prohibiting in operation of the signal element of the oil pressure protection is used to prevent automatic reclosure in the case of internal damage to transformers. The signal element of the oil pressure protection functions at the presence of gas in the relay or in case of oil leakage. When external short circuits occur, the signal element misoperates far more rarely than the tripping element. Therefore, prohibition of ARC operation by the signalling contact of the gas relay may be used to promote the operation of the ARC devices after tripping the transformer breaker for any reason, except internal faults. The operating time of the ARC devices should be somewhat greater than the operating time of the signal element of the oil pressure protection (3 to 5 s).

Starting of an ARC device from the back-up protection units of the transformer (or, which is the same, prohibiting ARC operation in case of internal faults, when the differential or oil pressure protection operates) is often used. Such starting, however, ensures no automatic reclosure when the transformer is tripped due to a short circuit on its terminals during operation of the differential protection and also because of malfunction of the differential or oil pressure protection (an example is external short circuits cleared after deenergizing).

At the same time, reclosing is possible with an internal short circuit, if the differential or oil pressure protection fails. Failure of the main protection units is unlikely and may be neglected. To ensure rapid tripping of the transformer in the case of reclosing to a short circuit, provision should be made to speed up the back-up protection installed on the breaker, after it is closed by the ARC device.

When a substation is equipped with a transformer supplied from one side an ARC device is compulsory. With three-winding transformers the ARC devices are installed on each of the breakers so that the breaker can be reclosed by the back-up protection after one of the transformer windings has tripped.

When a substation having only one source of supply is furnished with two or more transformers operating in parallel an ARC device must be considered as compulsory at least for one transformer. If the tripping of one transformer may overload another one with the resulting tripping of some loads an ARC device should be installed on another transformer.

It is practicable to start the ARC device by back-up protection units (for example, overcurrent time delay protections) connected into each tension circuit of the three-winding transformers, and connected from the supply side when two-winding transformers are used.

When ARC devices are installed on paralleled step-down transformers, provision should be made for the sequential closing of the breakers both to make the load of the storage battery lighter and promote another attempt to reestablish the supply to the consumer in case of unsuccessful initial automatic reclosure.

In the case of separate operation of the transformers, automatic reclosures may be provided when a protection device responding to external short circuits operates and the automatic transfer action caused by the operation of the protection unit responding to internal short circuits. Such a method eliminates the possibility of connecting a sound section of the substation to a persisting short circuit in the circuit of the backed up transformer.

When power sources are connected to busbars at different voltages the ARC device to be used should be selected to suit the actual operating conditions of the transformer at the substation and ensure synchronous connection of the respective voltages or the permissible asynchronous connection.

When the transformer is used to supply synchronous motors or synchronous capacitors, the operation of the ARC devices must be coordinated with the time for changing over the deenergized synchronous loads to asynchronous operation or with the time required to trip this load, as in the case with the ARC

operations on the lines. When a substation is equipped with autotransformers all the above-mentioned with regard to the use of ARC devices for transformers remains valid.

10-6. Conclusions

1. ARC devices are effective when adopted for the automatic reclosing of breakers placed in the circuit of power transformers (autotransformers), after they have tripped short circuits, or after malfunction of the protective relaying devices and when the tripping is inadvertently performed by attending personnel.

2. The circuits of the ARC devices used on the transformers are similar to those of the ARC units employed by transmission lines.

3. After operation of the differential protection of busbars and their deenergizing, the busbars can be reenergized with the aid of the ARC devices installed on the breakers of the outgoing terminations (feeders).

4. The percentage of successful transformer and busbar automatic reclosures is about the same as for transmission lines (more than 60 per cent on the statistical data).

5. After successful testing of the busbars, it is better for the normal supply to the substation to be automatically reestablished. Such automatic devices are applied in a number of power systems.

6. Automatic reclosure of the busbars with the reestablishment of the primary circuit of the before-fault service at power stations complicates the ARC circuit as it is necessary to prevent (in a number of cases) asynchronous connections of the generators. The final decision as to the automatic reestablishment of the normal service connections should be based on the analysis of the local service conditions.

10-7. Review Questions

1. How is the automatic reclosing of substation busbars accomplished (a) when differential protection is available and (b) when it is not?

2. Why is a more sensitive protection used when the condition of the busbars is tested by connecting them to the voltage through the breaker of one of the terminations (feeders)?

3. What is the difference in the methods of automatically reestablishing the before-fault service at substations and power stations?

4. Compare various circuits used for starting the ARC devices of power transformers.

5. How are the ARC devices realized on breakers of a three-winding 110/35/6.6-kV transformer, if the voltages at the 35 and 110-kV side may be asynchronous? Draw the circuit diagrams of the ARC devices.

6. How do you explain the successful operation of the ARC devices used on busbars and transformers?

7. How is the nature of the load connected to the substation busbars taken into account (whether it is asynchronous or synchronous) when applying ARC devices to a step-down transformer?

8. For step-down substations the differential busbar protection only trips the breakers of the feeders through which the substation is supplied. Explain, why this is so.

9. When may busbars be reenergized without preliminary inspection of the equipment?

10. The ARC devices installed on the breakers of a step-down transformer are deenergized for checking. May the attending personnel immediately reclose the transformer after it has been tripped by the protection unit?

Chapter Eleven

AUTOMATIC TRANSFER TO RESERVE SUPPLY AND EQUIPMENT

11-1. General

To make the power supply to the consumers more dependable, they are supplied from two sides. In this case a fault at one of the supply units and its tripping will not stop the supply to the consumers, as they will be fed through the intact links of the power system. At the same time, the two-side power supply (in a number of cases supply from many sources), obtained by the connection of the power circuits into a ring system and parallel operation of transformers, makes the protective relaying more complicated. The operating conditions for the equipment worsen due to the increase in the short-circuit currents and the operation of the paralleled parts of the power system becomes more difficult.

The use of a sectionalized power supply system materially simplifies the protective relaying, adds to its reliable operation, increases the residual voltages across the busbars of the supplying substations during short circuits on the distribution system and decreases the short-circuit currents, and in many cases creates the required operating conditions for the voltage and power flow. The main disadvantage of a sectionalized circuit is the interruption to the service when a fault occurs on the supply units. This disadvantage is eliminated materially by the automatic transfer of a load to the stand-by power sources when the basic elements, through which the loads are supplied under normal conditions, are tripped.

Under normal conditions the stand-by sources may be switched off or be under voltage and carry no load.

In other instances, the stand-by sources may be partially loaded, i.e., the whole load of the consumer is shared among the two (or more) generating units and these units perform stand-by functions for each other.

Manually placing a stand-by unit into action causes a prolonged interruption to the power supply and, as a rule, affects the production processes being serviced. A 20 to 30 s interruption in the power supply to the station service circuit makes the boilers shut-down and causes complete outage of the power station. It takes several hours to restart the generating units and bring the power station up to normal operation. A more than 3 s interruption in the power supply to certain chemical processes disrupts the process and it often needs more than a whole day to reestablish the normal process.

With radial power supply systems, the reliability of the supply to the consumers is materially improved by the use of automatic transfer devices (ATS)

which bring in the stand-by supply and reduce the supply interruption time to less than 1 to 2 s.

One of the first ATS systems employed in the power systems of the USSR for the house circuits of the Gorky power station was proposed by the author in 1930. The self-starting of asynchronous motors (with a phase wound and squirrel-cage rotor) is possible and permissible. This has been corroborated by the ATS service experience and the respective theoretical analysis [11-1]. The first ATS devices designed for the station-service installations were made to function only when internal faults occurred on the power transformers or on the house-circuit generators. Later the service offered by the ATS devices was extended to cover busbar faults, as busbar short circuits often self-cleared after deenergizing. This factor, as mentioned previously, determines the successful busbar reclosing*.

When a stand-by unit carries its load, then, if this unit is connected to a persisting short circuit on the busbars of the power source being remedied, the fault will extend to the loads supplied by the stand-by unit. To mitigate the effect of such operation, provision is made for introduction of a speeded up protection after the ATS operation to ensure the quick disconnection of the stand-by unit together with its loads from the busbars of the circuit being remedied.

Another solution, which prevents the extension of a persisting busbar short circuit to the loads of the stand-by unit when the busbars are reenergized, is the joint operation of the ATS and ARC devices. When a fault occurs on the supplying circuit elements and their supply to the consumer is interrupted, the latter is disconnected from the main source of power and transferred to the stand-by source. Thus, the ATS operation takes place only after the faulty element is tripped both at the side of the main source of power and at the side of the receiving busbars of the consumer. If a short circuit occurs on the consumer's busbars, no ATS operation takes place. This operation is prohibited by the protection responding to busbar faults, or the ATS device cannot be triggered. It is the ARC device on the supplying connections that functions.

When a short circuit on the busbars (or on the lines run from the busbars to the consumer if the failed line is not deenergized) clears, the power supply restores. If the fault persists the breaker closed by the ARC device is tripped open. For example, if the differential or oil pressure protection of the main supply transformer is operating, the ATS device closes, and if it is the overcurrent protection the ARC device functions.

Automatic reclosure of stand-by supply lines allows the supply circuit to be made cheaper and simpler. The use of ATS devices on overhead transmission lines is considered as a back-up measure and does not supersede the use of ARC devices on them. A deenergized line is reclosed from the ARC device, and if the automatic reclosure appears unsuccessful the line is automatically tripped at

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* With 3-10-kV installations the successful ATS and ARC operations at short circuits on the busbars sometimes depended on the fact that during short circuits the isolator leads burnt out and the arc had time to extinguish within the ATS or ARC cycle while the busbars were deenergized.

the receiving end and the ATS devices transfer the loads to a supply from another stand-by line which also carries its "own" load.

The ATS method is used not only for backing up the supply to the consumers, but also for promoting reliable operation of important mechanisms of the power stations and industrial plants (in place of the constant idle running of these mechanisms). Often automatic switching on of stand-by feed pumps, draft fans, coal feed mechanisms, blowers, etc. is provided.

As a rule, the automatic switching-over to a stand-by power source is done to provide emergency lighting and operation of communication and remote-control apparatus in the case of failure of the a.c. supply at the power station or substation used to energize these apparatus under normal operating conditions.

The simpler protective relaying obtained through the use of an ATS device has made it possible for a number of city power systems to ensure service with reliability acceptable by the consumers without further capital outlay. A so-named automatic discriminating reserve device (ADR) has been developed [11-2]. This device ensures the selective connection of transformer substations to the stand-by supply line after isolating the faulted section of the main supply line. For the selective tripping the simplest type relays such as current, voltage, time and auxiliary relays are used.

Data on the operation of ATS devices over 5 years obtained from the USSR Ministry of Electric Power Engineering [11-3] is given in Table 11-1.

As the analysis shows the ATS technique is an important means in improving the operation dependability of power systems. The number of successful

Table 11-1

Data on Five Years Operation of ATS Devices

Where installed	Data			
	number of set-years, K *	successful operation, %	Periodicity, year	
			successful operation	unsuccessful operation
Substation transformers (apparent reserve)	5,945	94	3.3	51.2
Transmission lines	16,895	94.9	4.7	87.3
Transformers of station service (apparent reserve)	11,046	91.1	4.7	46.3
Station-service motors	39,785	99.54	2.7	58.0
Intersection breakers for station-service (non-apparent reserve)	3,753	97.0	1.7	54.0
Intersection breakers of substation (non-apparent reserve)	8,316	89.2	4.4	36.5
Other objects of service	26,889	98.2	4.7	810.0
All installations	112,629	96.06	3.5	118.0

* K is the number of ATS devices times the number of years in use.

ATS operations totals 90-95 per cent. As with ARC devices, the efficiency of ATS devices is determined by how quickly the normal production processes are reestablished after reenergizing. This, in turn, depends on the no-power time, and whether the electric motors will start after the no-power time and how quickly the before-fault productivity is obtained. It is clear that the operation of an ATS device is anything but successful if the consumers' motors fail to start and if the operating ratings become critical during the starting time with resultant outage of the production process.

The above circumstance is a difficult problem to solve with regard to the choice of the supply circuit (multi-source supply without ATS devices or radial supply with ATS devices), protective relaying devices, characteristics of the motors and loads, commutation apparatus, control circuits and blocking devices.

11-2. ATS Device Circuits

ATS devices of power transformers supplied from common busbars. Fig. 11-1 shows the circuit of a step-down substation with two step-down transformers. The loads supplied from the substation busbars (lighting circuit, electrical furnaces and asynchronous motors) impose no limitations on the operating time of the ATS device and permit repeated application of voltage 1.5 to 2.5 s after a fault occurs. From the supply side the transformers are connected to a common busbar system, from the receiving side to two sections.

The possible operating conditions of the substation are as follows:

(1) Two transformers are connected to different sections with breaker *S5* being open.

(2) One of the transformers (transformer *T1*, for instance) is connected to the two sections with breaker *S5* being closed. Transformer *T2* is disconnected.

Under such conditions the ATS device assures:

The use of the transformers as stand-by units with respect to each other, when they operate into different sections.

Automatic transfer of a transformer as a stand-by unit when only one transformer is in operation and is tripped due to a fault.

Automatic reenergizing in the case of a short circuit on the busbars of the section during parallel operation of the transformers with the section breaker closed. Such operation may be advisable in order to balance better the loads of the transformers and reduce losses.

Reenergizing of section *II* is not provided in the case of a short circuit when transformer *T2* is tripped and breaker *S5* is closed. Section *I* cannot be reenergized when transformer *T1* is switched off and breaker *S5* closed. Under these conditions the required reclosing can be performed by an ARC device which closes when the stand-by protection of the transformer functions. This protection has a time delay and is installed from the supply side (this protection and the ARC device are not shown in Fig. 11-1). The operation of the stand-by protection prohibits operation of the ATS device (by disconnecting the coils of relays *3AR* and *4AR* from the operating current, for instance), while opera-

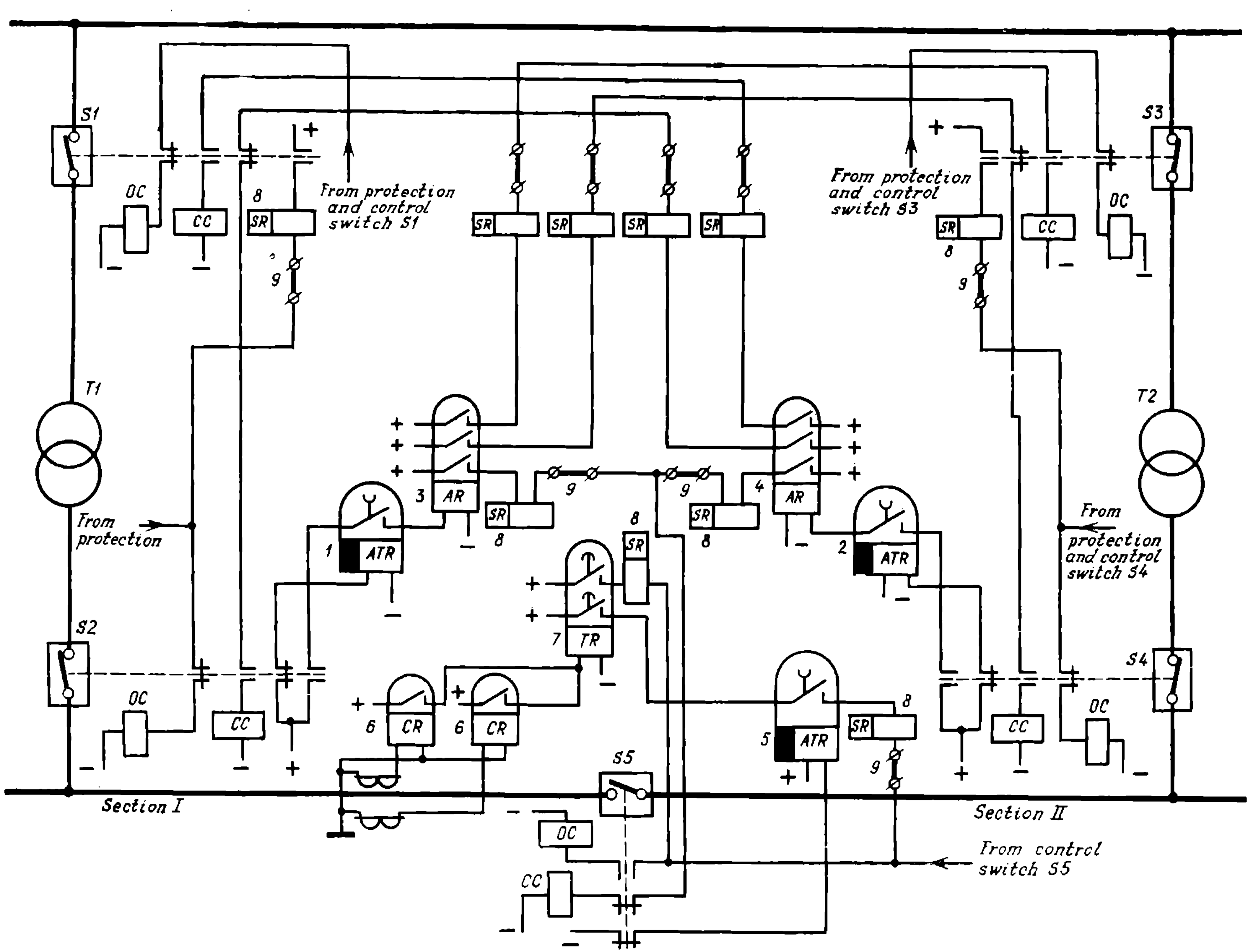

Fig. 11-1. Circuit of ATS device of transformers supplied from the common busbars of substation

1, 2, 5 — delayed reset relays; *3, 4* — auxiliary relays; *6* — current relays; *7* — time relay; *8* — signalling relays; *9* — jumpers (used in place of relays *6* and *7* may be overcurrent protection units of transformers, which trip the section circuit breaker in less time that the case is with the circuit breakers of transformers *T1* and *T2*). The position of breakers *S1* through *S4* and their auxiliary contacts corresponds to the closed position of the breakers)

tion of the differential and oil pressure protective units cancels the operation of the ARC device, and the ATS device is allowed to function.

The ATS device operates as follows:

Whatever the cause of tripping the breaker *S2* or *S4* (a short circuit on the busbars included), the auxiliary contacts of the breakers break and open the coils of relays *1* and *2* (relays with delayed armature dropout). After the coils are deenergized, the relay contacts open in 1.5 to 2 s.

Thus, after tripping the breaker *S2* or *S4*, relay *3* or *4* closes for 1.5-2 s and in its turn closes the section breaker and the breakers of the power transformer (if the latter has been tripped open).

The closing circuits of the breakers *S2* and *S4* are wired through the auxiliary contacts of the breakers *S1* and *S3* (the auxiliary contacts close after the breakers *S1* and *S3* close). This connection is provided to prevent the closing of the three breakers simultaneously which may overload the storage battery. The coil circuits of relays *3* and *4* open 1.5 to 2 s after the working transformer is disconnected, thus promoting a one-shot closing of the section breaker and the breakers of the stand-by transformer. The one-shot ATS in the case of a short circuit on the busbars of the section being remedied is obtained by making the breaker control circuit capable of blocking against multi-shot closures.

With operating times in excess of 0.5 s it is practicable to realize the protective relaying of the section breaker and the power transformers with an accelerated action after the operation of the ATS device.

As an example, Fig. 11-1 illustrates a possible circuit for accelerating the operation of the overcurrent protection of the section breaker. With the breaker *S5* tripped open, the coil of relay *5* carries a current and the contact of the relay is closed. After the breaker has been closed manually or by the ATS device to carry a short circuit burden, current relays *6* function and close time relay *7*. The latter completes the accelerated action circuit in 0.1 to 0.2 s. If relays *6* and *7* do not function after closing the breaker *S5*, the protection accelerating circuit is opened after a certain time by the contact of relay *5* and only the selective protection remains.

The use of the above-described circuit for accelerating the operation of the overcurrent protection of the section breaker is permissible if the current relays fail to operate due to the self-starting currents after closing the section breaker. Discrimination against these currents may sometimes lead to unwanted desensitization of the protective system. When this happens, the operating time of the accelerated protection is set to about 0.5 s [11-4] or use is made of an auxiliary current cutoff isolated against the starting currents, but operating from the short-circuit currents when a fault occurs on the busbars. The breaking circuit of this cutoff is normally open and is automatically closed a certain time after the section breaker is closed manually, remotely, or by the ATS device (i.e., this circuit is controlled by the contact of relay *5*).

If each of the transformers is not furnished with an individual ARC device and the transformers operate in parallel, then reenergizing in the case of a short circuit on one of the sections will be performed by the ATS device. For this, the section breaker must have a protection which will trip this breaker before the

action of the back-up protection of the transformer (or the back-up protection of the transformer should have two time settings, the smaller to trip the section breaker and the greater to disconnect the transformer). After the sections are separated and the transformer feeding the short circuit on the faulty section is disconnected, the ATS device functions and breaker *S5* reestablishes the voltage across the deenergized section at the expense of the section intact.

When the breakers *S1*, *S2*, *S3* and *S4* are opened manually and in cases when such disconnections deenergize one of the sections, as performed by mistake, (i.e., the ATS device is not disconnected deliberately), the ATS device will ensure the power supply from the other section.

To disconnect the ATS device, jumper (bridge) *9* is provided. This disconnection also can be accomplished by the control key switch disconnecting the ATS device from the source of operating current. The circuit has signalling relays *8* which indicate the operation of the ATS device and the path of a closing pulse to the breakers *S2* and *S4* after the breakers *S1* and *S3* have closed.

ATS devices of power transformers supplied from different power sources (Fig. 11-2). The transformers *T1* and *T2* are working units and the transformer *T3* is a stand-by one. The power supply to the transformers is from different sources (for instance, from different sections of the generation voltage). The ATS circuit shown in Fig. 11-2 differs from the above-described circuit in that the ATS operates not only when the transformer becomes disconnected, but also in the case of no-voltage across the section, whatever the reason may be, in particular, when the supply sources are disconnected or at fault. Voltage relay *1* through time relay *2* and auxiliary relay *7* makes the breakers of that transformer open whose section is at no-voltage.

The pickup setting of voltage relay *1* is as small as practicable (30 to 40% of U_n) in order to limit the reach zone in the case of voltage dips during a short circuit on the outgoing lines and also to discriminate against voltage drops during the subsequent self-startings of the motors. The setting of time relay *2* is greater than the operating time of the protection against short circuits occurring in the zone of residual voltage which is less than 30 to 40 per cent of U_n. The voltage relays are connected to different phases. The contacts of the relays are connected in series. This connection prevents false operation when one of the fuses blows.

The use of the ATS circuit shown in Fig. 11-2 may be permitted when the loads are asynchronous, lighting or heating ones. When the load is synchronous the ATS device must be supplemented with equipment that prevents asynchronous application of the voltage from the stand-by source to the busbars across which the voltage is maintained by the coasting synchronous motors with live field.

The circuit allows for installation of a relay indicating the voltage across the stand-by source. Use is made of one relay *5*, as it is unlikely that a fault occurs on its circuits during ATS operation. The protection accelerating circuits are not shown. The protection units installed on the section breakers have circuits similar to those illustrated in Fig. 11-1.

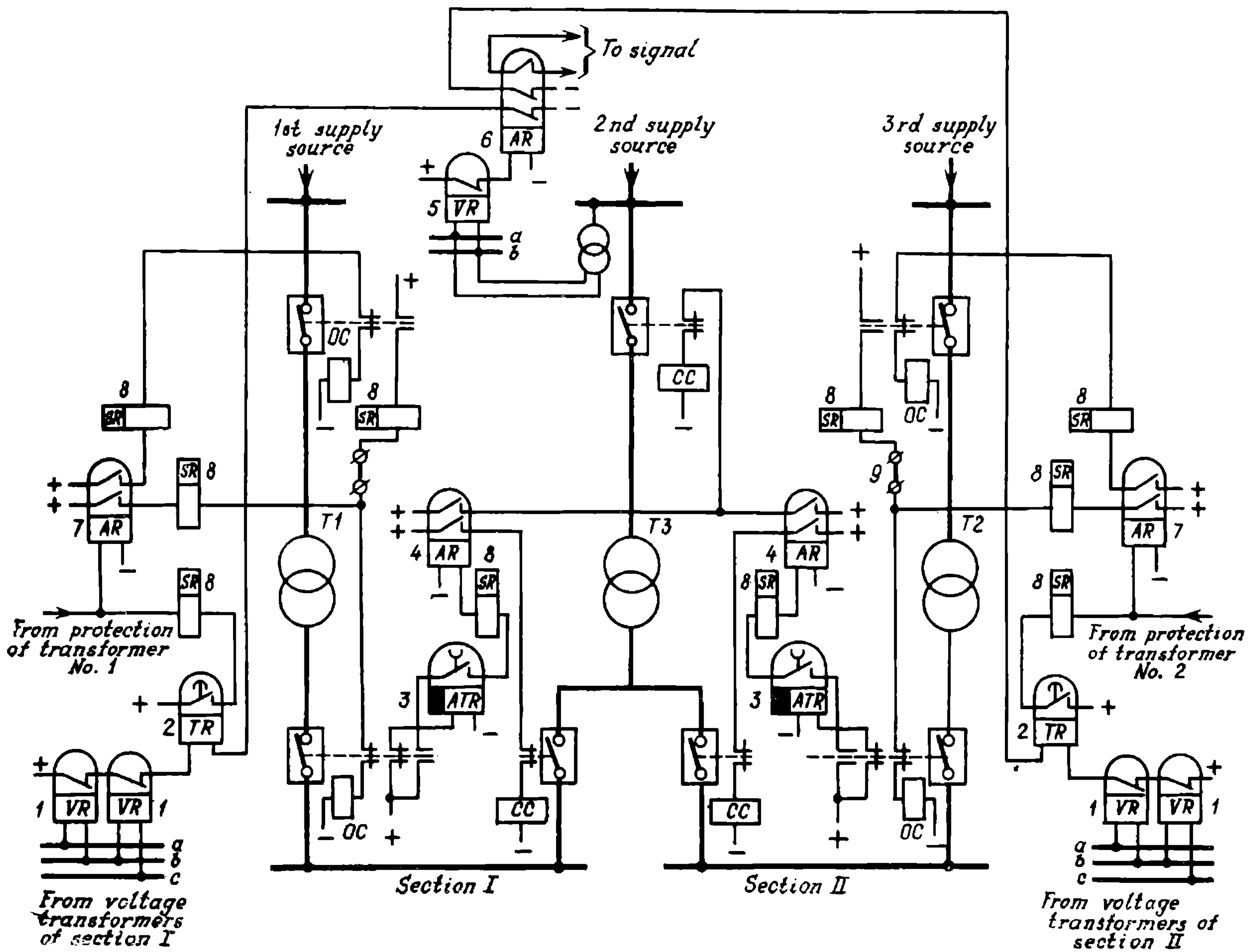

Fig. 11-2. Circuit of ATS device of transformers supplied from different power sources

1, *5* — voltage relays; *2* — time relays; *3* — delayed reset relays; *4*, *6*, *7* — auxiliary relays; *8* — signalling relays; *9* — jumpers. Positions of circuit breakers of transformers *T1* and *T2* correspond to their closed position

When an individual stand-by transformer is used (with simplicity in view) no ATS devices are generally provided on the working transformers. The stand-by transformer is furnished with an ARC device if one of the working transformers is disconnected for a long repair period. Under such operating conditions it is better to change the ATS circuit to that of Fig. 11-1 in order to make the power sources serve as stand-by units for each other.

When section is deenergized the asynchronous motors, coasting for a short time due to the accumulated energy, maintain the voltage, for which reason the action of the protection may be somewhat behind. To speed up the operation of the ATS device, when the supply transformer is disconnected, whatever the cause may be (when, for instance, an operator opens the breaker at the supply side by mistake), the circuit assures the tripping of the section breaker through the auxiliary contacts of the breaker found at the supply side of the working transformer.

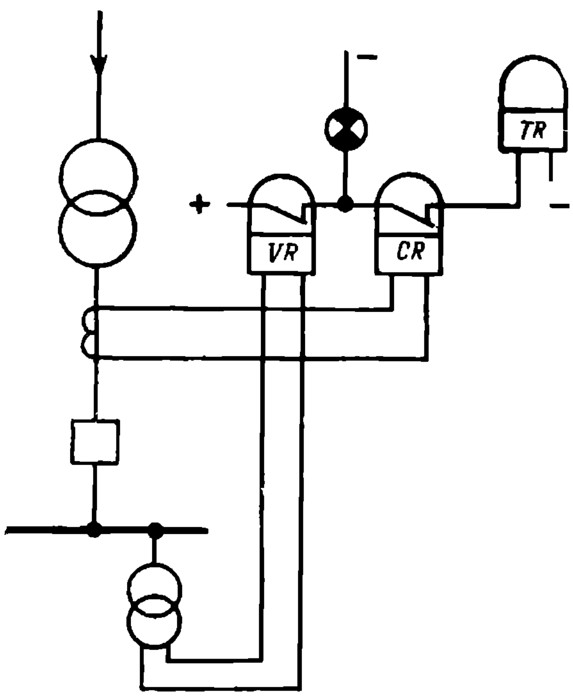

Fig. 11-3. Connection of voltage relay which indicates no-current in supply connection

When the section is deenergized, the tripping of the working transformer may be obtained through the voltage relay connection circuit shown in Fig. 11-3. This makes it possible to increase the pickup setting of the voltage relay to $U_{pickup} = 65\%$ of the rated voltage.

The time relay *TR* picks up when the voltage across the section busbars and the current flows in the circuit of the supply transformer disappear. This protects against improper disconnection of the working transformer due to false operation of the instrument voltage transformer circuits and in case of blown fuses. The circuit may be applied when the minimum operating current in the main supply circuit is sufficient to make the current relay function. The choice of the current relay should be such that it holds the contacts open at the minimum load and that its coil is sufficiently heat resistant to withstand the maximum possible operating currents.

When the working transformers are supplied through transmission lines equipped with ATS devices, the operating time of the starting element of the ATS device with a voltage relay and a current relay must be greater than the total time taken to clear the short circuit on the supply line and reclose the breaker by the ARC device. Thus, the transfer to the stand-by source is performed only in the case of unsuccessful automatic reclosure. If the line supplying the transformer is furnished with a two-shot ARC device the operating time of the undervoltage protection is generally isolated against the operating time of the ATS device in the first cycle.

The circuit of a transmission line ATS device (Fig. 11-4) is similar to that of the ATS devices installed on the transformers. When the voltage across the busbars disappears, voltage relays close the contacts and actuate time relay *2*. The operating voltage of voltage relay *1* is 30-40 per cent of U_n.

The setting of time relay *2* is greater than the total time taken for clearing the short circuit on the supply line and its automatic reclosure by the ARC

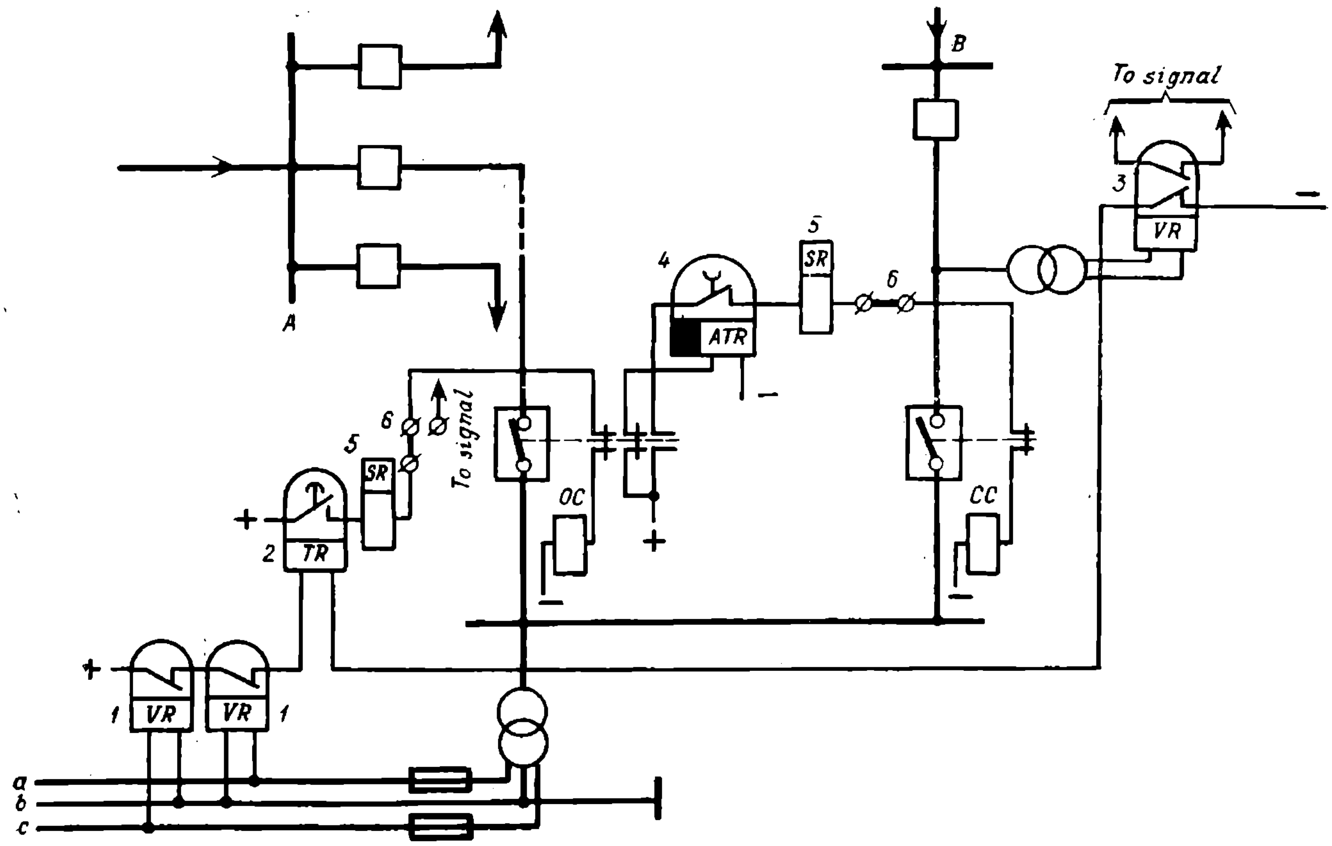

Fig. 11-4. Circuit of ATS device of power transmission lines
1, 3 — voltage relays; *2* — time relay; *4* — delayed reset relay; *5* — signalling relay; *6* — jumpers

device from the side of substation *A*. The setting of relay *2* should be also greater than the time needed to clear short circuits on other transmission lines and on the lines run from substation *A* in the zone of residual voltage equal to the pickup voltage of relay *1**. The stand-by supply line run from substation *B* should be under voltage. The presence of voltage is indicated by relay *3* connected to the voltage transformer of the stand-by line. Any device designed for taking off voltage (an example is power takeoff from the capacitor bushings of the circuit breaker or from suspension insulators) may be substituted for the

* When the ATS device is tripped for some reason, the voltage protection must be switched off.

voltage transformer. Delayed reset relay *4* ensures one-shot operation of the ATS device.

If the supply line is furnished with a two-shot action ARC device installed from the side of substation *A* and if after the second ARC operation the line remains under voltage the return of the substation to the main power source is best performed manually (locally or by means of a remote-control device).

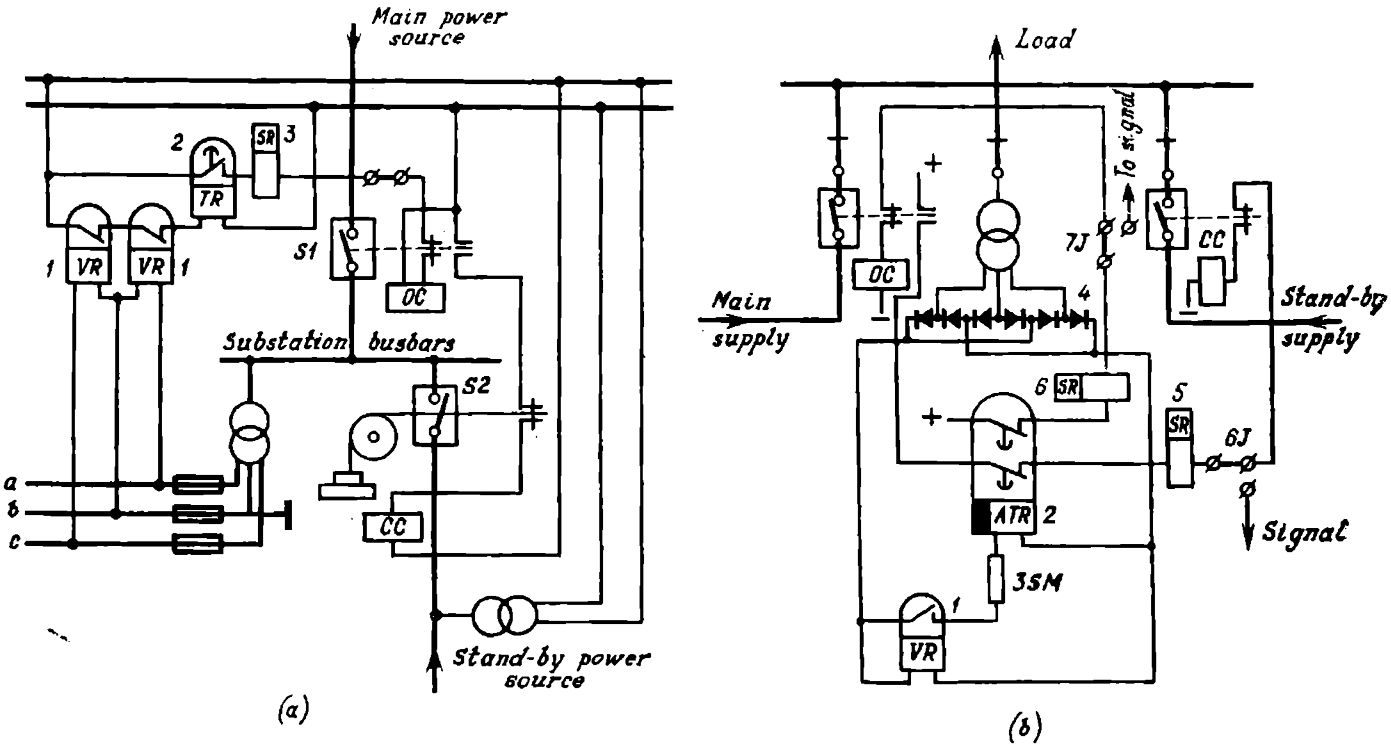

Fig. 11-5. Circuit of a.c. ATS device using weight actuators (*a*) and circuit of ATS device with voltage relay supplied with rectified alternating current (*b*)

When weight- or spring-type actuators are used at a receiving substation and there is no source of direct operating current available, the ATS device may be achieved in accordance with Fig. 11-5*a*. The breaker of the stand-by line closes when no current flows in the busbars of the receiving substation and a voltage is applied to the entrance of the stand-by source. Under these conditions the voltage relays close the contacts, time relay *2* functions and trips the breaker *S1*. The auxiliary contacts of breaker *S1* cut in the closing coil *CC* of breaker *S2* which cuts in the stand-by power supply. Time relay *2* is operated by alternating operating current. The same current is used to actuate the closing coil of the breaker *S2*. A voltage transformer connected to the transmission line of the stand-by supply source is used as the source of alternating operating current.

Figure 11-5*b* illustrates the circuit of an ATS device used with one-shot weight- or spring-actuated breakers. In the ATS device the sensing and actuating elements are combined in one relay *2ATR* with an armature reset delay of 1 to 5 s. The voltage applied to the coil of relay *2ATR* is taken from three-phase rectifier bridge *4* connected to the voltage transformer.

To improve the reset-to-pickup ratio of the ATS device, the coil circuit of relay *2ATR* is controlled by the contact of relay *1VR* (the reset voltage of relay *ATR* rated for 110 volts is about 10 volts, for which reason when no *1VR* relay is used and with the busbars deenergized, the relay *2ATR* may continue to be in the closed up position due to induced voltages). Any type voltage relay having a k_r of 0.5 or more may be used as the relay *1VR*. When the voltage across the busbars of the receiving substation disappears, the relay *VR* opens its contacts and deenergizes the coil of relay *2ATR* which, after the preassigned time, closes its contacts. The breaker used to cut in the main power source becomes disconnected. Its auxiliary contacts make the closing circuit of the stand-by supply breaker, which has been prepared by the contact of relay *2ATR*.

To accelerate the operation of the ATS devices, the tripping of the main power source breaker must be speeded up. To this end, the diagrams shown in Figs. 11-1 and 11-2 have circuits which perform such tripping operations when the breaker at the supply side of the main supply transformer is open. It is more complicated to accelerate the action of ATS devices employed at substations supplied from the main power sources over relatively long transmission lines.

The possibilities are as follows:

(a) To protect the supply lines, use may be made of a longitudinal differential protection which trips the line from both sides in the case of a short circuit.

(b) Use may be made of a device for rapid transfer of a tripping signal when the breaker at the supply line side is open, employing on the line in this instance a quickly acting protection (a current cutoff, for example).

(c) The line may be furnished with a protective system which quickly disconnects the line from both sides in the case of a short circuit, the system being based on the principle of protection with blocking (lock out) in the case of external short circuits.

(d) Use may be made of devices which rapidly indicate interruptions of real power flows in the line. Examples are a real power relay with and without operation indication with the aid of a frequency relay, a frequency relay seizing a decrease in the frequency and the rate of this decrease, etc.

The best results are obtained by using quickly acting protections installed both on the lines supplying the substation and on the other lines supplying power to the parallel loads. This makes it possible to set the time delay of the time relay, incorporated in the ATS device and triggered by a starting element of any type, to 0.5 s.

11-3. ATS Devices Used by Substations Supplying Synchronous Loads

A typical scheme used to supply power to many industrial enterprises is represented by consumer's (plant) distribution circuits fed from the main step-down substations over two trunk lines. Connected to each trunk line are the sections of consumer's busbars with a section breaker installed between them. Generally this breaker is open. It is closed by the ATS device in the case of an

interruption in the supply to the section after the supply trunk line entrance is disconnected. The use of two trunk lines allows them to be used as stand-by lines with respect to each other, providing that each section has a transmission capacity sufficient to carry the loads of both sections. This power supply system of industrial consumers allows simple-type protection units and ATS devices to be used, the high-standard performance of which has been corroborated by their application for many years on the station-service installations [11-5].

During an ATS cycle, the synchronous motors connected to the deenergized section lose their synchronism with respect to the stand-by source. ATS operation may be permitted either after disconnection of the synchronous load or after removal of its excitation and the transfer to starting operation. Both duties may be checked by the fact that the voltage across the busbars of the backed up section drops to a value at least lower than 65 per cent of the rated voltage. Thus, the operation of the ATS device after tripping the breaker at the main supply entrance (for instance, after the operation of protective relaying system) *must wait* for the voltage to drop to the specified value.

Asynchronous connection of an excited synchronous load from an ATS device may not be recommended for the following reasons:

(a) Asynchronous connection current is many times the designed nominal current of a synchronous motor, this connection may result in damage to the motor [11-6].

(b) Possible asynchronous operation which may cause the synchronous motors supplied from the other (intact) trunk line to lose their synchronism, i.e., disconnection of the two production process flow lines being supplied from the two trunk lines, which often completely destroys the production process.

(c) Certain types of synchronous motors do not permit resynchronization after asynchronous connection without additional measures being taken (an example is excitation removal and its subsequent reapplication after recovery of the voltage, or short-time unloading of the motor). Low-speed synchronous motors of piston-type compressors have such peculiarities [11-7].

To speed up the operation of ATS devices, when carrying synchronous loads, the ATS device circuit must incorporate elements which indicate any interruption in the power supply from the main source and remove, simultaneously with the tripping of the entrance from this source, the excitation of the synchronous motors being connected to the given section of the distribution substation. When necessary, the above-mentioned element must give a short-time unloading to the synchronous motor at the side of the mechanism being driven by this motor.

Complete disconnection of the synchronous motors with their subsequent manual reclosure cannot be regarded as a satisfactory solution of the problem, since the prolonged shutdown of important mechanisms driven by synchronous motors usually results in disturbance to the production process. This may be justified only when the shutdown mechanism is backed up by another one. For example, if a mechanism driven by a synchronous motor connected to one of the distribution substation sections works into same line as the mechanism

which has its synchronous driving motor connected to the second section of the distribution substation, shutdown of one of the mechanisms can cause no disturbance to the production process.

As mentioned above, elements that can indicate an interruption in the power supply to any of the distribution substation sections may be real power relays controlled by the operation of an underfrequency relay [11-8], or a relay responsive to frequency change rate or one responding to the difference between the frequencies of the two sections of the distribution substation [11-9].

It should be remembered that the voltage relays waiting for the voltage drop across the deenergized section may not function for a long time when the synchronous motors are not tripped and their fields are not discharged, for the voltage will be maintained by the coasting synchronous motors (for several seconds).

In order to speed up the operation of the ATS device started from a voltage relay, provision should be made for removal of the excitation of the synchronous motors (or for their disconnection) after the action of the protector on the supplying line or the transformer, with the breakers of the main and stand-by supply entrances being tripped at the same time.

11-4. ATS Devices with Standardization Control Stations

The standardized control stations are intended for transfer of the lighting load and power loads when the normal supply voltage disappears. The stations are to operate in d.c. and a.c. circuits at phase voltages up to 220 volts. Provision is made for switching of two and three poles, i.e., for switching of the circuits: phase-neutral, two phases and three phases with a neutral conductor. The ATS device may be accomplished with or without a time delay.

The operating principle of the ATS device intended for transfer to a stand-by power supply, when the main supply line is deenergized, is seen from Fig. 11-6.

Under normal conditions the busbars are supplied from *Entrance 1*. The stand-by supply is from *Entrance 2*. Key switch *1CK* controls the coil *C-1L* of contactor *1L*. The closing circuit is completed through the closed contact *2L-BC-2* (contactor *2L* is tripped open), jumper (bridge) *1J* and closed contact of *2ATR* (relay *2ATR* is deenergized as the key switch *2CK* is not closed).

The auxiliary contacts *1L-BC-1* of contactor *1L* make after it is closed. Next, a circuit forms through the bridge *2J* and closes relay *1ATR* whose contact *1ATR* opens the circuit of coil *C-2L* of the stand-by supply entrance. To prepare the circuits for automatic transfer to the stand-by supply, attendants have to close key switch *2CK*.

If the working entrance is deenergized (*Entrance 1*) the contactor *1L* drops out. Its auxiliary contacts *1L-BC-1* open the circuit of relay *1ATR*. The auxiliary contact *1L-BC-2* prepares the circuit for closing the contactor *K-2L* found in the circuit of *Entrance 2* (a stand-by supply entrance). After the armature

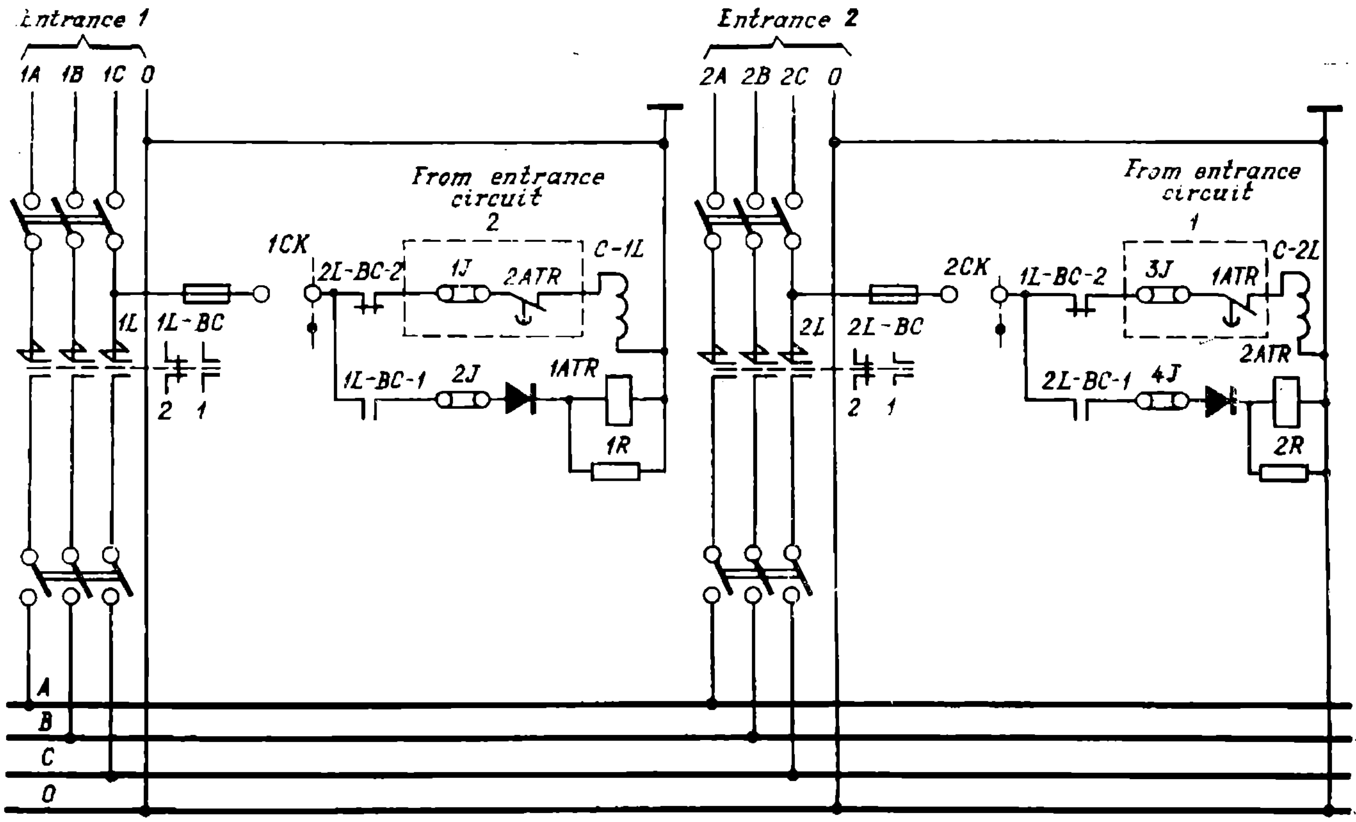

Fig. 11-6. Schematic diagram of ATS device with the use of control station

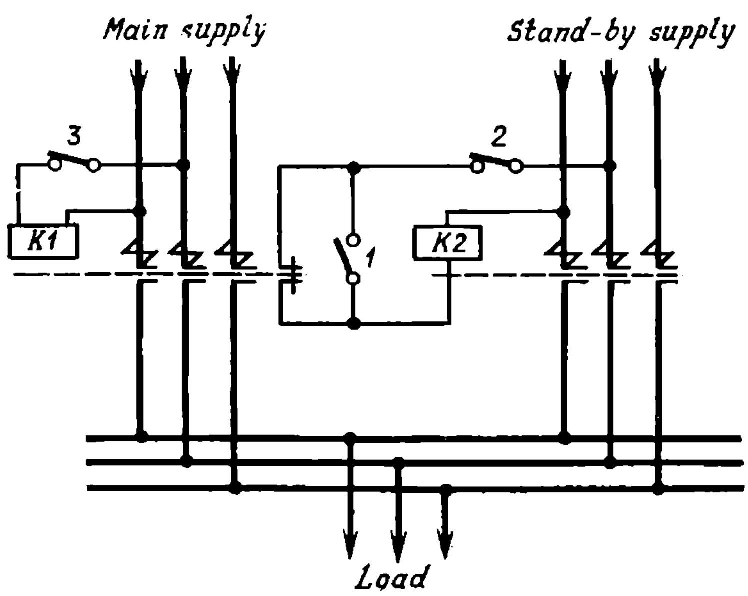

Fig. 11-7. Circuit of ATS device employing contactors

reset time has elapsed, the relay *1ATR* makes the closing circuit of the contactor of *Entrance 2*.

After the contactor *2L* has closed, the auxiliary contact *2L-BC-1* makes and closes the relay *2ATR* which opens the coil circuit for closing the contactor *1L*. Now *Entrance 2* performs the function of the main supply and *Entrance 1* is used as the stand-by supply source.

The time taken to close the stand-by supply by means of the relay *ATR* is 0.5 s in order to prevent the application of the stand-by supply voltage to the coasting excited synchronous and asynchronous motors. If no delay is required in the operation of the ATS device, the jumpers (bridges) *2J* and *4J* must be removed.

A simplified contactor circuit for ATS operations is shown in Fig. 11-7. Contactor *K1* of the main supply entrance is normally closed. When the entrance is deenergized the contactor drops out and closes its auxiliary contact which closes the circuit of the contactor *K2* that switches on the stand-by supply entrance. The instantaneous ATS action is determined by the tripping time of contactor *K1* and the closing time of contactor *K2*. The ATS device is isolated by closing knife switch *1*.

11-5. Self-Starting of an Asynchronous Load

Interruptions to the normal power supply occur during faults in the power supply circuit and when the ARC and ATS devices operate.

Short time (0.12 to 0.15 s) interruptions hardly brake the asynchronous load and most of the motors do not lose synchronism. That is why, where high-speed protection units and breakers are used, the short circuits have but little effect upon the loads and cause no self-unloading of the power system. With interruptions of seconds and more, which occur when the ARC (except HSARC) and ATS devices operate, the asynchronous motors may decelerate and even stop, and the synchronous motors must be transferred to asynchronous starting with subsequent resynchronization otherwise they lose their synchronism and must be disconnected.

Because of the above reasons the supply lines generally carry a current in excess of the normal value after voltage reestablishment.

If there is a possibility of the asynchronous load self-starting (synchronous motors transferred to the asynchronous starting mode are also asynchronous loads), the protective relaying calculations must take into account an increase in the currents. This phenomenon is evaluated by a starting factor K_s whose value depends on the composition of the load and whether the motors are furnished with a protector that deenergizes the motors when the voltage drops.

Voltage protection must be installed on less important equipment which is disconnected in order to facilitate the starting of the motors driving important mechanisms or for safety reasons. For the usual loads of receiving substations the value of K_s ranges from 1.5 to 3 and may be roughly determined on the basis of the following.

In the asynchronous motor equivalent circuits (Figs 11-8 and 11-9), x_{st} is the inductive reactance and R_{st} the resistance of the stator winding, x_r is the inductive reactance and R_r the resistance of the rotor winding, which are corrected to the number of turns of the stator winding; x_μ is the magnetizing reactance; s is the slip (with a standstill motor $s = 1$). In normal operation $s = s_n = 0.02$ to 0.04 (2-4%).

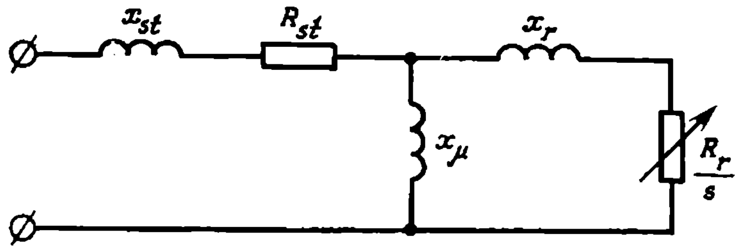

Fig. 11-8. Equivalent circuit of asynchronous motor

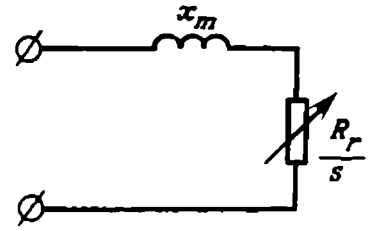

Fig. 11-9. Simplified equivalent circuit of asynchronous motor

When power is first applied to the motor a heavy current surge occurs, its value being determined by the reluctance of the motor iron core (a d.c. component surge of the starting current). Corresponding to this moment is the minimum reactance value x_μ which then rapidly increases. The starting current changes aperiodically. The initial surge of starting current decays in 1-2 cycles (Fig. 11-10) and does not effect the protectors having operating times of 0.06 to 0.1 s.

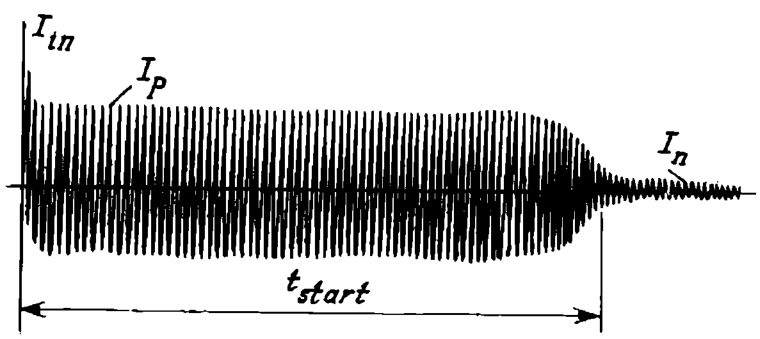

Fig. 11-10. Oscillogram of currents during starting of asynchronous motor
I_{in} — initial value of starting current, containing a.c. component and d.c. component; I_p— periodic component; I_n — normal current (current corresponding to slip $s = s_n$)

As the reactance x_μ rises very quickly and, in addition, the resistance of the stator winding is small as compared with the inductive reactance, a good analysis may be obtained from a simplified equivalent circuit (Fig. 11-9). The current flow in this circuit is

$$I = \frac{U_{ph}}{\sqrt{x_m^2 + \left(\frac{R_r}{s}\right)^2}} \tag{11-1}$$

To evaluate the value of the periodic component of the starting current, use is made of a term "critical slip" s_{cr}. Approximately the critical slip

$$s_{cr} \approx \frac{R_r}{x_m} \tag{11-2}$$

(it holds when $x_\mu \approx \infty$ and R_{st} is far less than x_m[11-10]). Placing (11-2) into (11-1) we obtatin

$$I = \frac{U_{ph}}{x_m \sqrt{1 + \left(\frac{s_{cr}}{s}\right)^2}} \tag{11-3}$$

The periodic component of the starting current (with $s = 1$)

$$I_s = \frac{U_{ph}}{x_m \sqrt{1 + s_{cr}^2}} \tag{11-4}$$

With asynchronous motors, $s_{cr} = 0.1$ to 0.2, hence

$$I_s \approx \frac{U_{ph}}{x_m} \tag{11-5}$$

In value this current is equal to the short-circuit current behind the lumped inductive reactance x_m.

Under normal operating conditions the current value is determined from (11-3). If $s = s_n$, then

$$I_n = \frac{U_{ph}}{x_m \sqrt{1 + \left(\frac{s_{cr}}{s_n}\right)^2}} \tag{11-6}$$

Thus, the starting current of an asynchronous motor connected across the line (at rated voltage) has the following multiplicity factors

$$K_{s.m} = \frac{I_s}{I_n} = \frac{\sqrt{1 + \left(\frac{s_{cr}}{s_n}\right)^2}}{\sqrt{1 + s_{cr}^2}} \tag{11-7}$$

or

$$K_{s.m} \approx \sqrt{1 + \left(\frac{s_{cr}}{s_n}\right)^2} \tag{11-8}$$

When $s_{cr} = 0.1$ and $s_n = 0.03$, $K_{s.m}$ is about 3.4 and when $s_{cr} = 0.2$. and $s_n = 0.04$, $K_{s.m}$ is about 5.

As it follows from (11-3) and (11-5)

$$I \approx I_s \frac{1}{\sqrt{1 + \left(\frac{s_{cr}}{s}\right)^2}} \tag{11-9}$$

The current factor decreases in proportion to the starting current with the decrease in the slip (Fig. 11-11). When $s = s_{cr}$ the current equals $0.71 I_n$. If a motor is started at a voltage lower than the nominal voltage the current decrea-

ses in proportion to it. For example, if a motor is connected across the line at a voltage equal to 70 per cent of U_n, the starting current will also be 70 per cent of the nominal value when the motor is started.

When the voltage is reestablished after a successful reclosure or after the operation of an ATS device, some of the motors disconnect (the motors of less important loads). Besides, the load of consumers substations includes not only the asynchronous motors. Therefore, with respect to the nominal current in the line, the multiplicity factor of the line current during an automatic reclosure, or ATS operation, is less than the multiplicity factor of the starting current of an individually started motor.

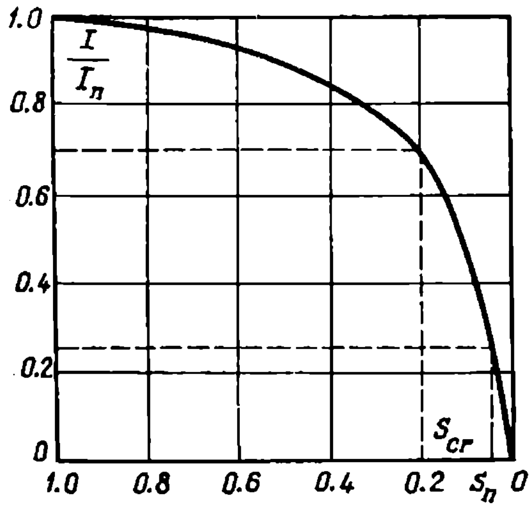

Fig. 11-11. Changes in current carried by stator windings of asynchronous motor versus slip

Moreover, the K_s value becomes less also because, after automatic reclosure (1-2 s after the voltage has disappeared), the asynchronous motors of most of the mechanisms are only braked a little, rather than stopped. Thus, if the value of the motor slip at the moment the voltage appears across the supply entrance is known, the starting current may be determined more accurately from equation (11-3).

In foreign practice, the application of ARC and ATS devices was purposely limited, as it was feared that there may be asynchronous closures of the unbraked asynchronous motors. Service experience has shown, however, that at no-power periods of 1 s or more, i.e., when ordinary-type breakers are used and there are no ARC and ATS devices, it is not necessary to employ additional blocking units [11-11], even if asynchronous motors are connected in parallel with capacitor banks. Where the capacitor banks are present, the emf decaying time of coasting asynchronous motors becomes greater but does not exceed 0.5 s.

The duration of the self-starting process depends on the magnitude of the voltage that appears across the motor terminals after a successful ARC and ATS operation, the reactionary torque of the driven mechanism and the slip value to which the motor is braked up to the instant the voltage is reestablished. In order to explain the basic conditions which determine a successful self-start, let us consider the specific features of asynchronous motor operation under normal and emergency conditions (at the normal and decreased voltages).

The torque developed by a motor is determined by the power lost in the resistance R_r/s of the equivalent circuit

$$T_m = \xi I^2 \frac{R_r}{s} \tag{11-10}$$

where ξ is a certain proportionality factor which takes into account the efficiency of the motor-mechanism unit.

With due consideration to (11-3) we have

$$T_m = \xi \frac{U_{ph}^2}{x_m^2\left(1+\frac{s_{cr}^2}{s^2}\right)} R_r/s \tag{11-11}$$

Taking into consideration (11-2), we obtain

$$T_m = \xi \frac{U_{ph}^2}{x_m \frac{x_m}{R_r} s\left(1+\frac{s_{cr}^2}{s^2}\right)}$$

$$T_m = \xi \frac{U_{ph}^2}{x_m\left(\frac{s}{s_{cr}}+\frac{s_{cr}}{s}\right)} \tag{11-12}$$

The torque developed by the motor at the nominal terminal voltage $U_{n.ph}$ is its maximum when $s = s_{cr}$

$$T_{m.\,\max} = \xi \frac{U^2{}_{n.\,ph}}{2x_m} \tag{11-13}$$

hence

$$T_m = T_{m.\,\max} \frac{2\left(\frac{U_{ph}}{U_{n.\,ph}}\right)}{\frac{s}{s_{cr}}+\frac{s_{cr}}{s}} \tag{11-14}$$

Usually the torque is related to the value of the torque developed by the motor under a rated load

$$t_m = T_m/T_n \tag{11-15}$$

When in relative units the torque of an asynchronous motor

$$\frac{t_m}{t_{m.\,\max}} = \frac{2\left(\frac{U_{ph}}{U_{n.\,ph}}\right)^2}{\frac{s}{s_{cr}}+\frac{s_{cr}}{s}} \tag{11-16}$$

Usually $t_{m.\,\max}$ is approximately $2t_{m.n}$.

In compliance with (11-16) the initial torque developed by the motor when $s = 1$ is

$$t_{m.\,i} = t_{m.\,t} \frac{2\left(\frac{U_{ph}}{U_{n.\,ph}}\right)^2}{\frac{1}{s_{cr}}+s_{cr}} \tag{11-17}$$

When $s_{cr} = 0.2$ and $U_{ph} = U_{n.ph}$; $t_{m.i}$ is approximately 0.4 $t_{m.\max}$.

If a motor is stopped, then, after being connected to the circuit, it can gain the required speed and attain normal slip, provided the torque developed by

the motor is greater than the reactionary torque t_r of the driven mechanism. Reactionary torques may be constant and independent of the mechanism speed of rotation (for instance, the reactionary torque of a mill, metal cutting machine-tools, metal rolling mills, etc.) or may depend on the speed of rotation (examples are the reactionary torques of smoke draught fans, pumps, blowers, etc.). Some torque characteristics of asynchronous motors and reactionary torques are shown in Fig. 11-12.

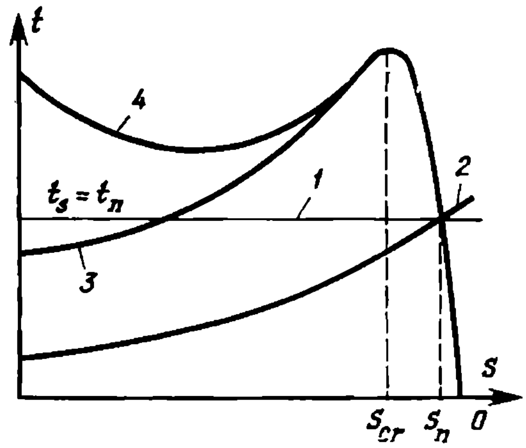

Fig. 11-12. Approximate characteristic of torques developed by asynchronous motor and load

1 — constant reactionary torque; *2* — load reactionary torque; *3* — torque of asynchronous motor with phase-wound rotor; *4* — torque of asynchronous motor with squirrel-cage rotor

So that an asynchronous motor can gain speed and drive a mechanism with a constant reactionary torque, it has a squirrel-cage rotor (a deep bar double-wound rotor) and a characteristic at which t_m is greater than t_r whatever the slip may be (curve *4* in Fig. 11-12). If a motor has a phase-wound rotor and the reactionary torque has a characteristic dependent on the slip (curve *2*), then the motor generally can gain speed, for in starting the terminal voltage of the motor is enough to develop a torque in excess of the reactionary torque.

As can be seen from (11-16), the torque developed by the motor is directly proportional to the square of the voltage across the stator terminals. In order to ascertain the fact whether a motor is capable of self-starting after reclosing across the line, it is important to know the value of this voltage across the motor terminals.

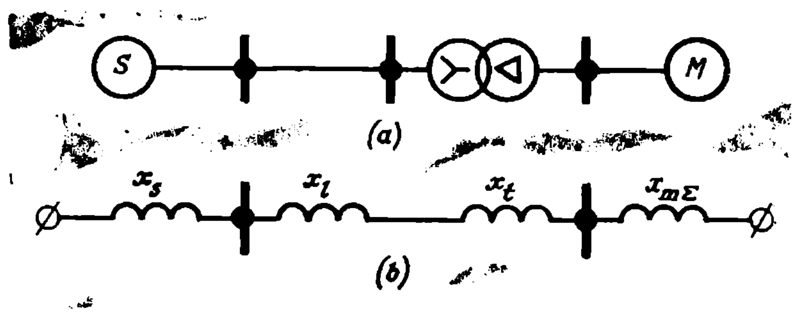

Fig. 11-13. Calculation diagram

(*a*) circuit diagram; (*b*) equivalent circuit

After an interruption in the supply, the first to self-start must be the motors of the most important mechanisms.

So that we may calculate the value of the asynchronous load which may remain connected and determine the value of the asynchronous load which must be disconnected by the undervoltage protection or other means in order to ensure the self-starting of the most important motors, we assume that the braked motors and power system elements (generators, transformers and transmission lines) have reactances in the equivalent circuit (Fig. 11-13). To include the

resistances make the calculations more complicated without any positive influence on the answer.

In the case of the self-starting of all the receiving substation asynchronous motors their reactances are calculated in compliance with (11-5). If the multiplicity factor of the periodic component of the starting current is known, then

$$x_{m\Sigma}=\frac{U_{n.\ ph}}{I_{s\Sigma}}=\frac{U_{n.\ ph}}{K_{s.\ m}I_{n\Sigma}} \tag{11-18}$$

where $I_{n\Sigma}$ is the total nominal current of all the asynchronous motors.

If only a few of the asynchronous motors (α) are self-started, the reactance of these

$$x_{m.\ ss}=\frac{1}{\alpha}\,x_{m\Sigma} \tag{11-19}$$

The total starting current is

$$I_{s.\ ss}=\frac{U_{n.\ ph}}{x_s+x_l+x_t+x_{m.\ ss}} \tag{11-20}$$

where x_s, x_l and x_t are the reactances of supply power system, line, and transformers, respectively, as measured between the point of emf application and the stator winding terminals of the asynchronous motor (equivalent).

The residual voltage across the motor terminals which provides the self-starting can be accepted as 70 per cent of U_n. In this case, the initial torque is about 50 per cent of the initial torque developed by the motor at the normal voltage.

In compliance with (11-19) and (11-20)

$$0.7U_{n.\ ph}=I_{s.\ ss}x_{m.\ ss}=\frac{U_{n.\ ph}}{(x_s+x_l+x_t)+\dfrac{x_{m\Sigma}}{\alpha}}\,\frac{x_{m\Sigma}}{\alpha} \tag{11-21}$$

hence

$$0.3\,\frac{x_{m\Sigma}}{\alpha}+0.7\,(x_s+x_l+x_t)$$

or

$$\alpha=0.43\,\frac{x_{m\Sigma}}{x_s+x_l+x_t} \tag{11-22}$$

$$\alpha\ \%=43\,\frac{x_{m\Sigma}}{x_s+x_l+x_t} \tag{11-23}$$

Tests carried out by some organizations show that self-starting of asynchronous motors can take place at motor terminal voltages even less than 70 per cent of the nominal value.

For example, the time taken to bring the station-service mechanisms up to the required speed was 32 s with a voltage drop to 54 per cent of U_n and a no-power interval of 3.9 s when self-starting. When the no-power time was reduced to 0.44 s, the run-up time of the mechanisms decreased to 1.2 s and the voltage across the motor terminals, after turning on the station-service section, was equal to 68 per cent of U_n.

The long time periods to attain the required speed and heavy voltage drops are unwanted, as they can cause a dangerous reduction in machine efficiency (which, in turn, may spoil the production process) and current overloads both

to the self-starting electric motors and the components in the power supply system. In this connection, the self-starting of the station-service auxiliaries at the power stations and also the loads supplied from the generation voltage busbars is helped materially by excitation forcing. ATS operations and reduction of the no-power time in the ARC and ATS cycles to a value not in excess of 1 s.

For more accurate calculations to determine the asynchronous load which may remain energized and its self-starting can take place after the voltage is reestablished, attention must be paid to the coasting and acceleration of a group of asynchronous motors, i.e., to the fact, that in a first approximation the inertia constant of a group of paralleled mechanisms may be taken as the weighted-mean of the inertia constants of the individual mechanisms. The actual characteristic of the torques developed by the motors of the given type is important. For instance, the tests at high-steam pressure stations have shown that to ensure the self-starting of the station-service asynchronous motors with no-power intervals greater than 0.5 s the busbar voltage of the station-service section after the operation of the ATS device must not be less than 75 to 80 per cent of U_n[11-12].

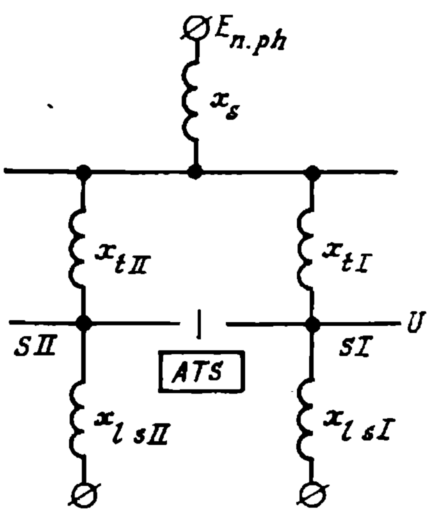

Fig. 11-14. Calculation diagram

Thus, the final decision on the self-starting of the load composed of asynchronous motors is better made after full-scale experiments have been carried out.

In certain instances it is practicable to use protective relaying devices to disconnect some of the important loads in order to promote the self-starting of loads that are critical in the production prosess. After the reestablishment of the voltage these loads are automatically restarted by the ARC devices [11-16]. When installing an ATS device to connect the substation sections having power transformers used as stand-by sources with respect to each other (Fig. 11-14), the load carried both by the busbars of the section deprived of the voltage and the busbars of the stand-by supply section must be considered. We illustrate this by an example.

Substation sections SI and SII are supplied from transformers TI and TII and operate separately. The power outputs of the transformers are S_{tI} and S_{tII}.

The loads of each section are asynchronous squirrel-cage motors.

$$P_{lI} = S_{lI} \cos \varphi_I = \gamma_I S_{tI} \cos \varphi_I \tag{11-24}$$

and

$$P_{lII} = S_{lII} \cos \varphi_{II} = \gamma_{II} S_{tII} \cos \varphi_{II} \tag{11-25}$$

where γ_I and γ_{II} are the coefficients characterizing the power transformer loads under normal operating conditions.

Assume that $\cos \varphi_I = \cos \varphi_{II} = 0.8$ and the multiplicity factor of the starting current $K_{s.m}$ is the same for all motors. When a fault occurs on transformer TII after it is tripped, the ATS device closes the section breaker. Thus, section SII is switched over and supplied from transformer TI. Find the percentage of asynchronous load at which self-starting takes

place when, after the ATS device has closed the section breaker and during the self-starting operation, the voltage across the *SI* and *SII* busbars remains at least 70 per cent of U_n.

Assume that the asynchronous motors connected to the *SII* section have stopped completely while it was deenergized. In this case, the closing of the section breaker is equivalent to a short circuit behind a reactance equal in value to the reactance of the *SII* motors waiting for self-starting as determined from (11-18)

$$x_{m.\,ssII} = \frac{U_{n.\,ph}}{K_{s.\,m} I_{n.\,m.\,ssII}} \qquad (11\text{-}26)$$

where the nominal current of the motors to be self-started is

$$I_{n.\,m.\,ssII} = \frac{P^{kW}_{m.\,ssII}}{\sqrt{3}\, U_{n.\,iph} \cos \varphi_{II}} \qquad (11\text{-}27)$$

Thus

$$x_{m.\,ssII} = \frac{3U^2_{n.\,ph} \cos \varphi_{II}}{K_{s.m} P^{kW}_{m.\,ssII}} \qquad (11\text{-}28)$$

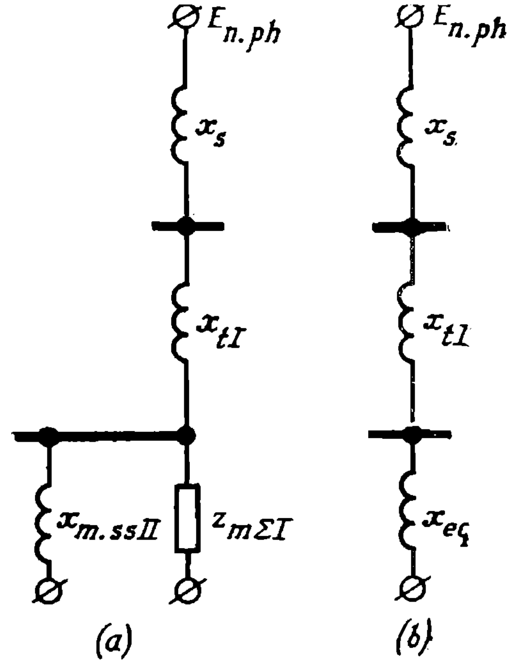

Fig. 11-15. Equivalent circuit

According to the condition of the example, the *SI* busbar voltage decreases after the section breaker is closed and becomes equal to 0.7 U_n; the torque developed by the motors connected to *SI* decreases in proportion to the square of the voltage, and their slip increases. The slip depends on the coasting characteristic and their operation duration at the reduced voltage, i.e., on the duration of the self-starting process.

To find the critical conditions, we assume that the self-starting of the *SI* motors will be difficult and long, which means that the slip of the motors will attain the s_{cr} value. When this is so, the torque developed by the *SI* motors will be at its maximum (at a given voltage across the stator terminals), while the current will be of about 50 per cent the starting value when starting the standstill motors at the rated voltage, the torque being almost fully reactionary.

The impedance of the *SI* motors at slip $s = s_{cr}$ is determined from the expression

$$|z_{m\Sigma I} \text{ at } s = s_{cr}| \approx x_{m\Sigma I} \sqrt{1 + \left(\frac{s_{cr}}{s}\right)^2} = 1.4 x_{m\Sigma I} \qquad (11\text{-}29)$$

As this impedance is almost fully reactive, then to simplify the calculations, the equivalent circuit (Fig. 11-15*a*) corresponding to the starting process period, when the *SI* motors are braked and the *SII* motors start gaining their speed, may be presented with less detail (Fig. 11-15*b*).

In this circuit the equivalent reactance x_{eq} is determined from

$$\frac{1}{x_{eq}} = \frac{1}{x_{m.\,ssII}} + \frac{1}{1.4 x_{m\Sigma I}} \qquad (11\text{-}30)$$

As

$$x_{m\Sigma I} \; \frac{3U^2_{n.\,ph} \cos \varphi_I}{K_{s.\,m} P_{tI}} = \frac{3U^2_{n.\,ph}}{K_{s.\,m} \gamma_I S_{tI}} \qquad (11\text{-}31)$$

then, taking into account (11-28), we obtain

$$\frac{1}{x_{eq}} = \frac{K_{s.\,m} P_{m.\,ssII}}{3U^2_{n.\,ph} \cos \varphi_{II}} + \frac{K_{s.\,m} \gamma_I S_{tI}}{1.4 \cdot 3U^2_{n.\,ph}} \qquad (11\text{-}32)$$

In order to sustain the residual voltage across the section busbars at a value not less than 70 per cent of U_n when the self-starting process takes place, it should comply with (11-22), so that

$$x_{m.\,ss}=\frac{x_{m\Sigma}}{\alpha}=2.33\,(x_t+x_s+x_l)=2.33x_t\,(1+\beta) \qquad (11\text{-}33)$$

where

$$\beta=\frac{x_s+x_l}{x_{tI}} \qquad (11\text{-}34)$$

The transformer reactance

$$x_{tI}=\frac{3U^2_{n\ ph}}{S_{tI}}\,\frac{u_{sc}\%}{100} \qquad (11\text{-}35)$$

Substituting this expression into (11-33) and taking (11-32) into account, we obtain

$$\frac{1}{2.33\,(1+\beta)}\,\frac{100}{u_{sc}\%}\,\frac{S_{tI}}{3U^2_{n.\,ph}}=\frac{K_{s.\,m}P_{m.\,ssII}}{3U^2_{n\,.ph}\cos\varphi_{II}}+\frac{K_{s.\,m}\gamma_I S_{tI}}{1.4\cdot 3U^2_{n.\,ph}}$$

hence

$$\frac{K_{s.\,m}P_{m.\,ssII}}{\cos\varphi_{II}}=S_{tI}\left(0.43\,\frac{100}{u_{sc}\%}\,\frac{1}{1+\beta}-\frac{K_{s.\,m}}{1.4}\,\gamma_I\right) \qquad (11\text{-}36)$$

Consequently, the power of the self-starting motors should be

$$P_{m.\,ssII}\leqslant S_{tI}\left[0.43\,\frac{100}{u_{sc}\%}\,\frac{1}{1+\beta}-\frac{K_{s.\,m}}{1.4}\,\gamma_I\right]\frac{\cos\varphi_{II}}{K_{s.\,m}} \qquad (11\text{-}37)$$

If in the example being considered $\gamma_I \doteq 0.7$; $K_{s.\,m} = 4.3$; $\cos\varphi_{II} = 0.8$; and $\beta \leqslant 1$ (i.e., $x_l = 0$ and $x_s/x_{tI} \leqslant 1$) and $u_{sc}\% = 10\%$, then

$$P_{m.\,ssII}=S_{tI}\left(0.8-\frac{0.7\cdot 0.8}{1.4}\right)=0.4S_{tI}$$

If the power output of transformers *TI* and *TII* are equal and this is the case with the loads of *SI* and *SII*, then the normal load of section *SII* (for the given example)

$$P_{m.\,nII}=0.7S_{tI}\cos\varphi=0.56S_{tI}$$

Hence, the asynchronous load percentage which may be left under voltage and can be self-started after the ATS operation is

$$\alpha=\frac{0.4}{0.56}\,100\approx 70 \text{ per cent}$$

Thus, when the voltage drops, the protection must trip about 30 per cent of the section asynchronous load. If transformer *TI* is not loaded and it is intended only for backing up trnasformer *TII*, then $\gamma_I = 0$ and, as seen from (11-37) the power of the self-starting motors may be equal to

$$P_{m.\,ssII}-S_{tI}\,\frac{0.43\cdot 100}{(1+\beta)\,u_{sc}\%}\,\frac{\cos\varphi_{II}}{K_{s.\,m}} \qquad (11\text{-}38)$$

For the given example

$$P_{m.ssII}=0.8S_{tI}$$

If the normal load of the section amounts to 70 per cent of the transformer rating, then

$$\alpha=\frac{0.8}{0.56}\,100=140\%$$

i.e., the motor need not be tripped.

When the self-starting process proceeds quickly and the slip of the motors supplied from SI rises, but little as compared with the normal value, the value of the second term of (11-37) will be less, i.e., a greater percentage of the asynchronous load may be left for self-starting.

When determining the input power of the motors left for self-starting, after the operation of the ATS devices of the transformer or reactor-connected station-service line, as a first approximation one may use Table 11-2.

Table 11-2

Approximate Permissible Percentage of Asynchronous Load Left in ATS Cycle for Self-Starting (referred to the power of supply transformer)

Circuit reactance up to station-service busbars, 2-6 kV (reduced to power of supply transformers), %	Deenergized section picked up by transformer	
	unloaded	loaded
8	175	150
10	145	120
12	120	100
14	100	80

The table is constructed on the assumption that the multiplicity factor of the starting current relative to the nominal value is 5, the terminal voltage of the asynchronous motors after ATS operation is 55% of U_n, and $\cos\varphi = 0.85$.

When the deenergized section is picked up by a loaded transformer, it is assumed that the slip of the working motors increases but little as compared with the normal value (roughly twice) and the transformers are connected to infinite-power busbars or to the generation busbars, provided the generators concerned are furnished with high-speed excitation forcing devices and automatic voltage regulators.

To promote an effective performance of the ARC and ATS devices, one has, in addition to ensuring the self-starting of important loads, to prevent the tripping of the asynchronous motors of the given loads in the short-time no-power intervals encountered during the ARC and ATS cycles.

To meet these requirements, the following steps are taken:

(a) For important asynchronous motors rated at 3 kV and more no undervoltage protection is used or, if used, its time setting must be sufficient to overlap the self-starting time (10 s).

(b) For asynchronous motors tripped with a view to facilitate the self-starting of important loads, use is made of undervoltage protection having a setting of 65 to 70 per cent of U_n, which trips the breaker at the mentioned voltage drops in 0.5 s.

(c) In order to automatically reestablish normal operation upon completion of the self-starting operation on the important loads, the tripped motors are restarted automatically. For this, use is made of ARC devices waiting for recovery of the voltage or time delayed ARC devices performing sequential reclosures in one or several groups.

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(d) For important asynchronous motors rated for voltages up to 1000 volts, use is made of magnetic starters having a dropout delay overlapping the no-

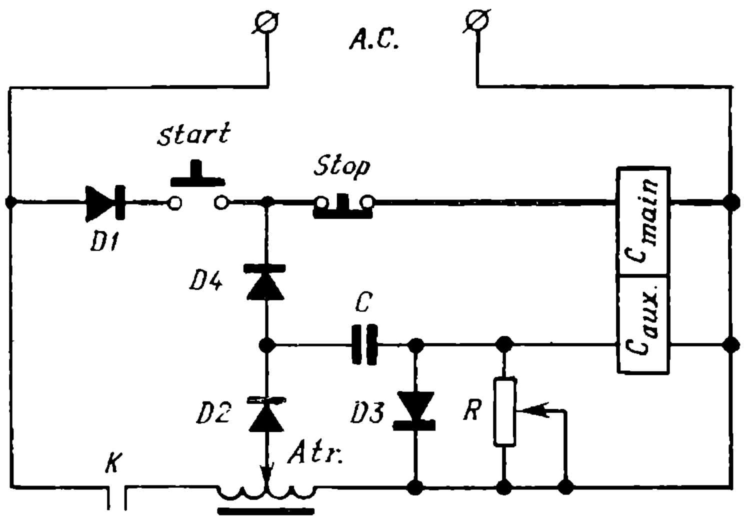

Fig. 11-16. Schematic diagram of delayed starter

power intervals in the ARC or ATS cycles (an example is shown in Fig. 11-16) or immediately start the motor after the voltage is reestablished (an example is in Fig. 11-17) [11-13, 11-14].

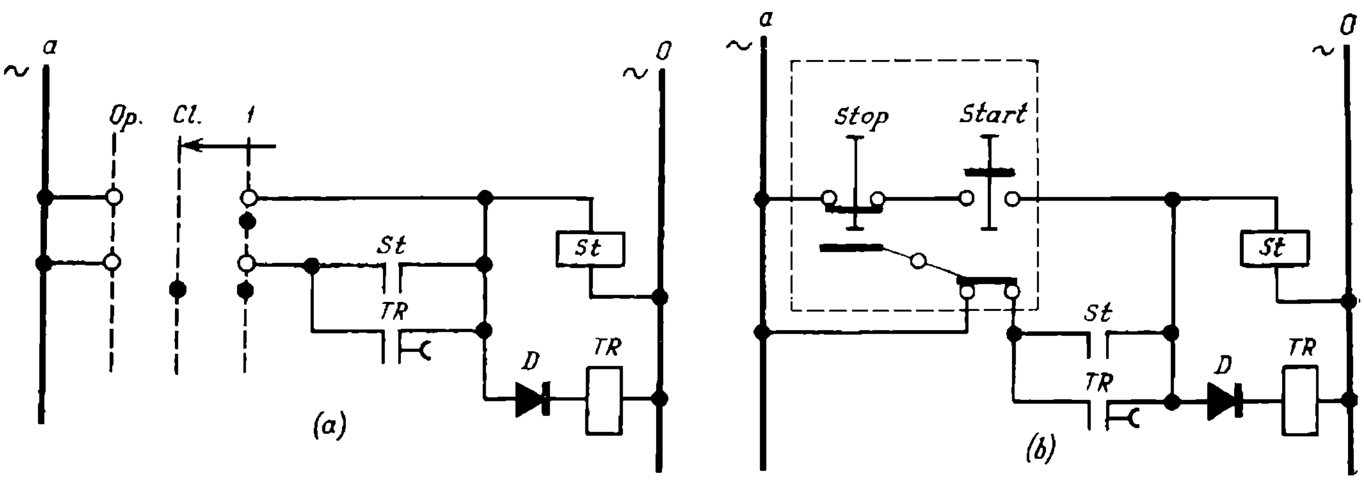

Fig. 11-17. Schematic diagram of starter for immediate reclosure when voltage is reestablished within the specified time

(*a*) with control contactor; (*b*) with button-type device; *St* — starter; *TR* — relay with delayed dropout of armature (up to 3 s); *D* — rectifier. Position of contactor: *1* — to be closed; *Cl* — closed; *Op* — opened. Transfer from position *1* to position *Cl* is performed without interruption

The device shown in Fig. 11-16 operates as follows.

The holding system of the starter has two coils, main and auxiliary, carried by a magnetic circuit core. When the starter is switched on by the *Start* button, the alternating current rectified by diode *D1* is fed to the main coil. After the starter has been switched on, its auxiliary contact *K* turns on the step-down

autotransformer *Atr* and the circuit including diodes *D2* and *D4* holds the starter locked until the *Start* button returns to the initial position. Simultaneously, the capacitor *C* starts to charge through diode *D3* used to bypass the auxiliary coil of the starter. When the *Start* button is pressed, the capacitor is protected against overvoltages by diode *D4*.

The starter is switched off by pressing the *Stop* button which opens the circuit of the main coil. The switching-off takes place immediately. In case the a.c. voltage disappears the capacitor *C* starts to discharge. With respect to the discharging current, the main and auxiliary coils turn out to be cumulatively connected in series. In this instance, the discharge time constant increases and additional forces hold the armature attracted for the reqiured time. This time is controlled by the value of resistance *R* which influences the discharge time constant of capacitor *C*.

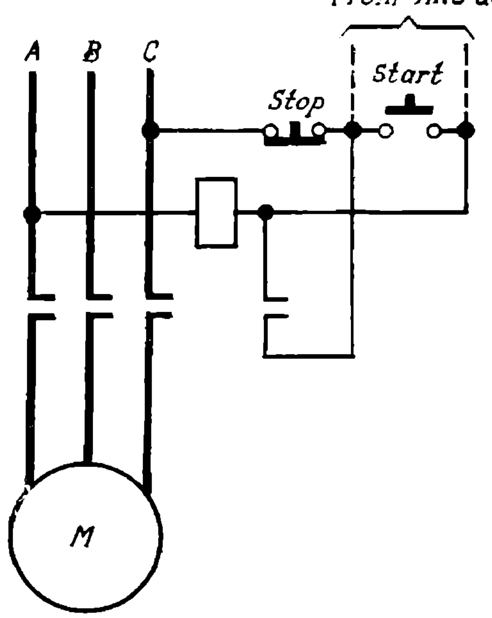

Fig. 11-18. Magnetic starter without immediate reclosure after voltage is reestablished

If the starter has to disconnect due to operation of some service automatic device, then connected in series with the *Stop* button is the contact of the output relay of the automatic device. The contact opens when the service parameters reach critical values.

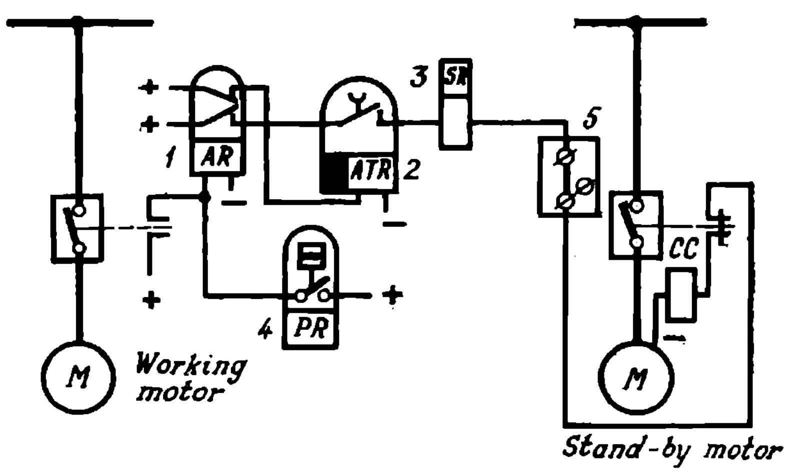

Fig. 11-19. ATS device of motor

1 — auxiliary relay; *2* — relay with delayed reset; *3* — signalling relay; *4* — pressure relay; *5* — tripping device. Position of auxiliary contact of circuit breaker of working motor corresponds to closed state of the breaker

The device shown in Fig. 11-17 ensures the immediate reclosure of a tripped motor after its terminal voltage is reestablished, provided that the interruption

in the power supply has not exceeded the dropout time of the auxiliary relay *TR* with delayed reset.

The circuit illustrated in Fig. 11-17 is one of the most simple variants of various starter designs with immediate reclosing when the voltage is reestablished within the specified time [11-13]. From the point of view of safety regulations and production processes an unlimited voltage reestablishment waiting time for reclosing the breakers cannot be permitted.

The circuit of a magnetic starter providing no immediate reclosure after the voltage has been reestablished is shown in Fig. 11-18. When it is necessary to reclose it after a specified period or in a preassigned sequence, the circuits shown in broken line can be used by connecting them, for instance, to the ARC device of the given unit.

In those cases, when the generation units have to perform the duty of a stand-by source for each other, only one of the motors operates under the normal conditions (working one, Fig. 11-19). When it is disconnected for any reason and, in particular, when the main source working voltage fails or falls sharply, the stand-by motor is automatically connected. It is supplied from the stand-by source [11-15].

11-6. Conclusions

1. The use of ATS devices at power stations and substations of power systems helps to ensure a dependable power supply and in many cases simplifies the circuit and protective relaying. The combined operation of ARC and ATS devices adds still more to the reliable operation of power systems.

2. The use of ATS devices assures sectionalization of substation busbars and reduces short-circuit currents, facilitates the equipment operation and cuts down costs.

3. ATS devices produce the best results when a deenergized network includes lighting and heating loads and also asynchronous motors whose self-starting may be attempted after the power supply is reestablished.

4. When a network incorporates synchronous motors, operation of the ATS devices of the supply service entrances must be coordinated with the action of the automatic controls which transfer the motor into the asynchronous starting mode and perform resynchronization after the supply is reestablished in a way similar to that used by the ARC devices of substations with synchronous loads.

Connecting a stand-by source to excited asynchronous motors should be avoided as far as practicable. In particular cases, such connection may be effected after checks to see whether it is tolerable as to the mechanical strength of the motor and its resynchronization and if such connection will not disturb the synchronism of the stand-by source motors.

5. The circuits of ATS devices should be as simple as possible. These devices are applied on installations with direct operating current and on the equipment supplied from an alternating operating current source.

6. When ATS devices are used, the protective relaying calculations must be always carried out with consideration given to the increased currents encountered in the self-starting of asynchronous motors. When the no-power interval in the ATS cycle exceeds 0.5 s, the terminal voltage of the motor disappears almost completely and may be neglected in the calculations. When the no-power interval is less than 0.5 s (0.1 s, for instance), the terminal voltage of the asynchronous motor has no time to vanish and it may oppose the line voltage in the ATS operation with a resulting increase in the mechanical loads suffered by the motor and an excessive starting current inrush as compared to the current inrush when cutting in a fully stopped asynchronous motor.

7. Automatic switching-on of stand-by supply sources needs investigations into the conditions necessary for the self-starting of important mechanisms which ensure continuity of production processes (examples are station-service auxiliaries and industrial productive mechanisms).

11-7. Review Questions

1. What is the difference between the automatic transfer to stand-by power and automatic reclosure?
2. On which power station auxiliaries are ATS devices most practicable?
3. How is the operation of the ARC and ATS devices installed on the step-down power transformers of substations coordinated?
4. Why does the excitation forcing of generators facilitate the self-starting of asynchronous motors in the station house circuits after operation of the ATS devices on the transformers which supply power to the station-service sections from the generating voltage busbars?
5. How does an increase in the output power rating of power transformers employed by substations effect the self-starting conditions of the consumers' asynchronous motors being supplied from the substation busbar sections?
6. Describe the specific features of a system used to control the contactors and magnetic starters of asynchronous motors left for the self-starting purposes.
7. What are the conditions determining successful self-starting of asynchronous motors after the operation of ATS devices?
8. Enumerate the disadvantages and advantages of the sectionalized supply to busbars with the use of ATS devices as compared to a circuit with parallel-connected sections.
9. How is the use of an ATS device taken into account, when accomplishing the protective relaying of consumers and supply units of the power system?
10. How is the presence of synchronous motors supplied from the busbar sections of step-down (low-tension) substations taken into account when accomplishing an ATS device? Draw a circuit diagram of an ATS device that waits for a voltage decrease across the busbars.
11. What are the methods used to detect voltage failure on the main supply line?
12. Think of and draw an ATS circuit which detects voltage failure by a real power directional relay and an underfrequency relay. Envisage the action of this detecting element on the automatic field discharging devices of synchronous motors with the simultaneous switching of the rotor winding to a resistance. Design a circuit for resynchronizing a motor after the normal voltage across the supply section is reestablished.

Chapter Twelve

OPERATION OF ARC AND ATS DEVICES IN CONJUNCTION WITH PROTECTIVE RELAYING

12-1. Acceleration of Protection Action Before ARC

Acceleration of the protection action before ARC allows the short-circuit clearing time to be reduced and adds to the reliable operation of the loads. Accelerating the action of a protective relaying unit before the operation of an ARC device is accomplished by a non-selective high-speed protector installed on the protected line together with the main selective protection. After the

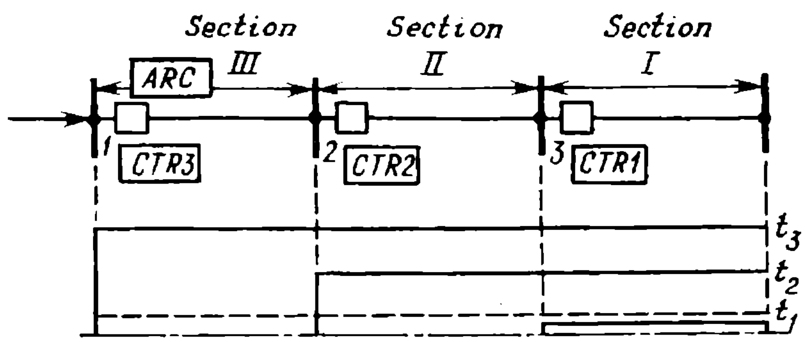

Fig. 12-1. Characteristics of protection units when their operation is accelerated before automatic reclosure

operation of the ARC device, the non-selective high-speed protection is automatically rendered inoperative for a period greater than that needed to trip the line by the selective protection, say, by a current protection with a stepped operating time characteristic (Fig. 12-1).

The use of accelerated protection before the ARC operation makes it possible for an ARC device to be installed only on the pilot section, ensuring reclosures of all the sections of the outgoing line chain. This method produces good results on short lines or when the circuit breakers of receiving substation are not adapted for automatic reclosing. The characteristic of the protection, whose operation is accelerated before the ARC operation, is shown in broken line.

When a fault occurs on any section of the transmission line the breaker of the pilot section opens and recloses. This quickly clears 60 to 70 per cent of the faults, as after ARC operation the insulation in the majority of cases is reestablished. When short circuits are cleared with a time delay (without

accelerating the protection action) the number of successful automatic reclosures is materially reduced. In the case of connection to a persisting short circuit, retripping is performed selectively, as the non-selective protection is automatically disconnected.

Accelerating the action of the protection before ARC operation in the ARC circuit on Fig. 8-3 can be realized, if the break contact of time relay *TR* is applied.

12-2. Acceleration of Protection Action After ARC, ATS, and Remote Connection

Accelerating the protection action after the breaker is closed by an ARC or ATS device, or remotely by hand or a remote-control system, allows a faulted element to be immediately isolated if a short-circuit connection is made despite the fact that the element protection is delayed in time. This method minimizes the effect of short-circuit connections on the operation of the loads. The damage is mitigated and the parallel operation stability of the power system generators is also improved [12-1]. It is advisable to use the accelerated protection in all instances when high-speed protection of an element is not used at all or it covers only part of the line.

Accelerating the protection action after ARC operation in the circiut of an ARC device shown in Fig. 8-3 can be accomplished by using the contact of relay TR, the operating time of which is 0.1 to 0.15 s. The time during which the accelerated protection unit is set into operation by the instantaneous contact of relay *TR* is determined by the final contact time. The closure of this contact resets the device.

To accelerate the protection action in the circuit in Fig. 8-3 not only after ARC operations, but also after closing the breaker by hand, it is good practice to perform the operating closures of the breaker through acting upon the relay *TR*. In the circuits shown in Figs 8-4 and 8-5 the protection action is accelerated after any remote closure of the breaker by relay *ATR* which is delayed in the armature dropout after the coil is deenergized. With the breaker in the tripped position, this relay carries a current and closes the make contact. This prepares the circuit for the accelerated protection action. After the breaker has closed, relay *ATR* becomes deenergized and some time later (1-1.5 s) opens the accelerated protection circuit. The opening must take place after the breaker has closed and the accelerated protection has operated.

The method of accelerating the protection action after ARC and ATS operations is always used when the object is furnished with other than high-speed protection, i.e., when use is made of a protection with stepped time delay characteristics. In particular, when use is made of a stepped remote protection, either the second zone may be accelerated after the ARC operation or the first zone may be prolonged by means of an accelerating relay, i.e., 0.3 to 0.5 s after the breaker is closed; the relay *ATR* in Fig. 8-4 changes the operating setting of the first zone of the remote protection and lengthens the zone of action to

120 per cent of the line length. Till this moment the action zone was only 80 to 85 per cent of the line length.

To discriminate against the effect of the starting current inrush in the asynchronous motors, the current protection against interphase short circuits, responding to full currents, is accelerated to 0.15-0.5 s. The latter figure relates to the instances when the protection, functioning after the operation of an ATS device installed on the circuit breakers of station-service stand-by transformers is accelerated [11-4]. The protection responding to the zero-sequence currents is accelerated up to 0.1-0.15 s in order to isolate currents which appear due to the nonsimultaneous closure of the breaker phases. It is good practice to connect such a protection to the current transformers through a quickly saturable auxiliary current transofrmer so that the effect of the d.c. component in the zero-sequence current is eliminated.

The method is also applied in order to realize the high-speed protection of long 500-kV lines through the use of "trial" devices which switch on the nonselective high-speed protection for a certain time, with the line closed at one end, when the main high-speed protection of the given line is inoperative.

12-3. High-Speed Selective Disconnection

The joint operation of the protective relaying and ARC devices allows selective disconnections to be accomplished by nonselective protection units. Two methods are developed in the USSR [12-2, 12-3].

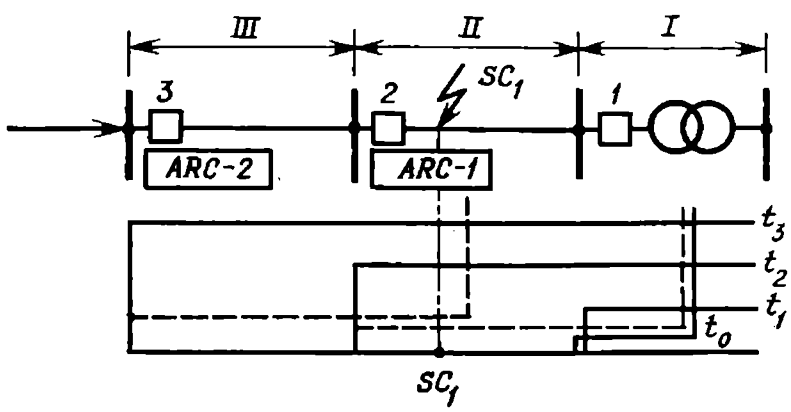

Fig. 12-2. Correction of nonselective action of protection by ARC device

(a) *Increasing the number of automatic reclosures as the section approaches the pilot section.* The operating time of the main protection is chosen according to the step principle. An additional instantaneous protection is installed to cover the section under protection and part of the next section. A nonselective current cutoff or nonselective distance protection is used as the additional protection (Fig. 12-2).

When a fault occurs in the action zone of the instantaneous protections of two adjacent sections (section *II* and section *III* at point SC_1, for instance) both sections are tripped and reclosed by the ARC device.

When the automatic reclosure is successful the supply is reestablished. If the short circuit persists, both sections are disconnected again. Next, the operation of the two-shot ARC device in the second cycle will reclose section *III*

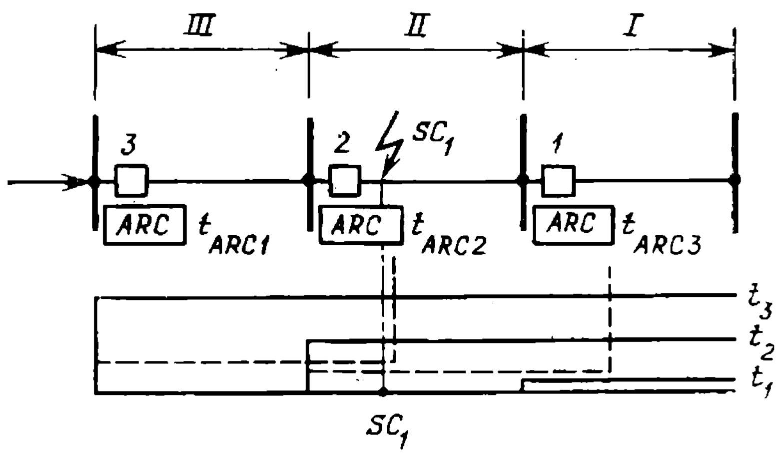

Fig. 12-3. Characteristics of protective relaying during sequential automatic reclosures

and will not reclose section *II*, as the latter is furnished with a single-shot ARC device. The figures found near the ARC symbol in Fig. 12-2 stand for the number of automatic reclosures performed by the ARC devices.

Within section *I* (a power transformer) protected by a current cutoff or differential protection, the ARC device does not function when these protections operate. Therefore when there is a persisting fault within their active zone and section *II* is tripped, the nonselective disconnection is corrected by the ARC device installed in section *II* (on breaker *2*).

This method enables a rapid selective disconnection to be obtained without using costly and complicated protections, confining oneself to the use of ordinary current cutoffs or single-stage distance protections. The disadvantage of this method is the possibility of simultaneous protective operations on two adjacent sections and the deenergizing of the loads supplied over a sound line for the operating time of the ARC device and closing of the breakers. When the ARC device or a breaker fails the fault will develop.

The method is applied when single- and two-shot ARC devices are used. Three-shot automatic reclosing to correct the nonselective operation of the protection is not practicable, as the result is a prolonged interruption to the service, which is determined by the operating time of the three-shot ARC devices.

(b) *Sequential automatic reclosures of transmission line sections.* In addition to the protection which selectively disconnected a faulted sections, each section is furnished with an instantaneous protection. The reach of this protection covers the section under protection and part of the next one (Fig. 12-3). Like

in the method described above, the protection is presented by a current cutoff or single-stage distance protection.

Now consider the operation of the protection and automatic reclosing when faults occur within the reach of the instantaneous protections of two adjacent sections (section *II*, section *III* at point SC_1, for instance). If a short circuit occurs at point SC_1 both sections disconnect in one operation. Section *III* which is closer to the power source is reclosed by the ARC device within a shorter time. As this happens, the nonselective protection from the side of the supply substation still remains closed for some time. If the insulation of section *III* is reestablished during the deenergized state of the line, the line remains

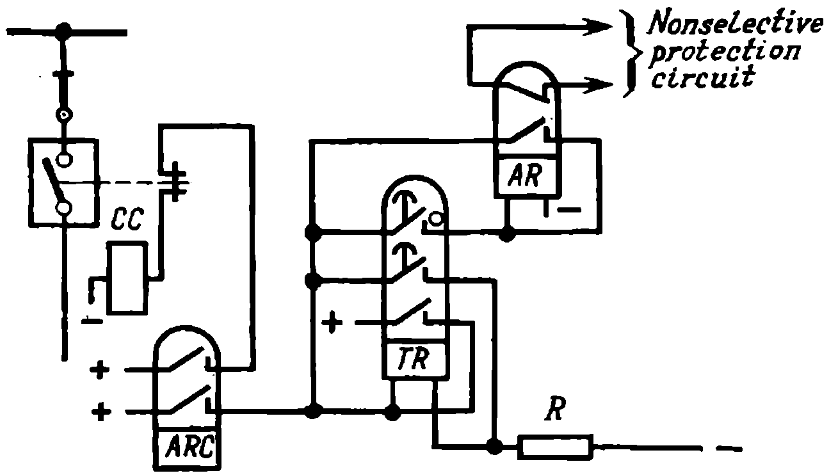

Fig. 12-4. Withdrawal of nonselective protection from operation during sequential automatic reclosures (variant of circuit)

connected. Next, the ARC device in section *II* operates. The time taken by it to close the breaker is greater than the total time taken to close the breaker of the ARC device located in section *III* and the time of subsequent tripping of the breaker if it is connected to a persisting short circuit.

At the moment the breaker is closed by the ARC device of the more remote section *II*, the selective protection of the nearer section *III* is automatically rendered inoperative. Thus, if a short circuit occurs in a more remote section and the fault persists during the disconnected state of the section, this section will be selectively tripped (section *III* will remain energized, as its nonselective protection is disconnected by the instant section *II* is switched on).

The nonselective protection of section *II* is automatically removed from the operation by the ARC device some time later after the breaker of section *II* is closed. The next reclosing of the nonselective protection of section *III* takes a time exceeding the total period of switching on section *II* by the ARC device and the subsequent disconnection of the section if the fault persists. When a fault occurs in section *I* the operation of the protection and ARC devices is the same.

A circuit for switching the nonselective protection is shown in Fig. 12-4. Simultaneously with feeding a closing pulse, the ARC device closes the circuit

of time relay TR which holds itself by an instantaneous contact. A little later after the breaker is closed the sliding contact completes the circuit of the auxiliary relay AR. The relay AR opens the nonselective protection circuit before the last-to-operate contact of relay TR closes. The time settings of the sequential automatic reclosure devices is intimated from the example given below.

Let the circuit (Fig. 12-3) be furnished with a sequential automatic reclosure device. We choose:

(a) The time needed by the ARC device to close the breakers.

(b) The time for disconnection of the nonselective protection.

(c) The time required to reset the device element disconnecting the nonselective protection, say, for section *III*.

Being given the operating time of the ARC device in section *III* as equal to 1 s. Disconnection of the nonselective protection of section *III* is carried out after the closure of the sliding contact of relay TR (Fig. 12-4). This time is

$$0.8+0.1+0.15+0.3=1.35 \text{ s}$$

Where 0.8 is the breaker closing time, 0.1 s is the operating time of the nonselective protection, 0.15 s is the breaker tripping time, and 0.3 s is the margin time.

The operating time of the ARC device in section *II* is selected so that the closure of breaker *II* takes place after the nonselective protection in section *III* is disconnected

$$t_{\mathrm{ARC}2}=1+1.35+0.3=2.65 \text{ s}$$

where 1 s is the operating time of the ARC device of section *III*, 1.35 s — the closing time of the sliding contact of relay TR of the circuit shown in Fig. 12-4, and 0.3 s — a margin time (additional margin time results from the fact that the contacts of the breaker make 0.6 to 0.8 s after the operation of the ARC device in section *II*).

The operating time of the final making contact of relay TR in section *III* is determined from the fact that the nonselective protection of section *III* can be reestablished only after the ARC device has closed section *II* which is tripped again by the nonselective protection in the case of a persisting fault.

The making time of the last-to-operate contact of relay TR of section *III* is

$$(2.65-1)+0.8+0.1+0.15+0.5=3.2 \text{ s}$$

where 2.65 s is the operating time of the ARC device of section *II*, 1 s — the operating time of the ARC device of section *III*, 0.8 s — the closing time of the breaker of section *II*, 0.1 s — the operating time of the nonselective protection of section *II*, 0.15 s — the tripping time of the breaker of section *II*, and 0.5 s — a margin time.

As compared to the method used to correct nonselective action of the protection with the aid of ARC devices with increasing the number of reclosures, the sequential automatic reclosure method has the advantage as it needs no two-shot ARC devices. Moreover, the breakers do not isolate a short circuit more than twice in succession. The disadvantage of the sequential automatic reclosing is that when the next in sequence section is connected by the ARC device with a greater time delay the high-speed nonselective protection of the previous section must be disconnected. If a fault occurs in this section at this time it is cleared by the low-speed selective protection.

12-4. Substations Without Circuit Breakers on the High-Tension Side

The costs of a receiving substation may be reduced by installing isolators and short-circuiters on the high-tension side in place of circuit breakers (Fig. 12-5). When the power transformer is at fault its protection trips the breaker on the low-tension side and engages the short-circuiter on the high-tension side.

In circuits with heavy earth-fault currents, a single-pole short-circuiter is used. A two-pole short-circuiter is applied in circuits with light earth-fault

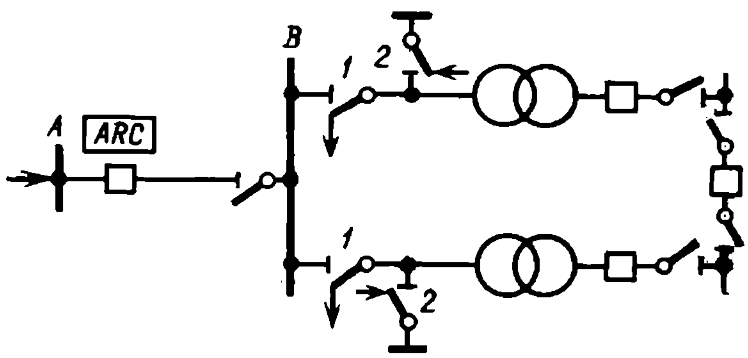

Fig. 12-5. Supply circuit of substation without breakers on the high-tension side

currents. Closing the short-circuiters causes a short circuit in the high-tension circuit and makes the protection from the supply substation side function (this protection may function earlier, if its sensitivity is sufficient to operate at a fault in the transformer). The breaker from the side of substation A trips. A compulsory condition is the tripping of the breaker from the side of substation A only after the closing of the short-circuiter with the result that the protection must be decelerated, otherwise the breaker may connect to a persisting short circuit caused by failure of the isolator to function during the no-power interval (see below).

After closing the short-circuiter, it carries a short-circuit current (Fig. 12-6*a*). Opening the breaker from the side of the supply substation causes the cessation of current flow in the circuit of the short-circuiter and in the primary of current transformer *12*. While the short-circuiter carries the short-circuit current, the coil of electromagnet *3* functions and deenergizes after the short-circuit current is stopped. The compressed spring forces striker *13* to knock out latch *4*. Isolator *6* trips open. A similar action causes the relay *3TR* (Fig. 12-6*b*) to function, this takes place after the blocking contacts *5BC-2* have checked the closed position of the short-circuiter and the closed contact of relay *2CR* has checked the current flow through the short-circuiter, i.e., the open position of the breaker from the supply substation side. After the specified time, which is enough to allow the isolator to trip the circuit of the faulted transformer for sure, the ARC device recloses the breaker A (Fig. 12-5) and reestablishes the service to the loads supplied from the intact transformer.

In order to avoid an increase in the operating time of the protection from the side of substation A, the protection is sometimes allowed to operate in the case of faults in the power transformer before the short-circuiter has closed. In this instance, unsuccessful action of the ARC device is possible, as the automatic device between the short-circuiter and the isolator will not function

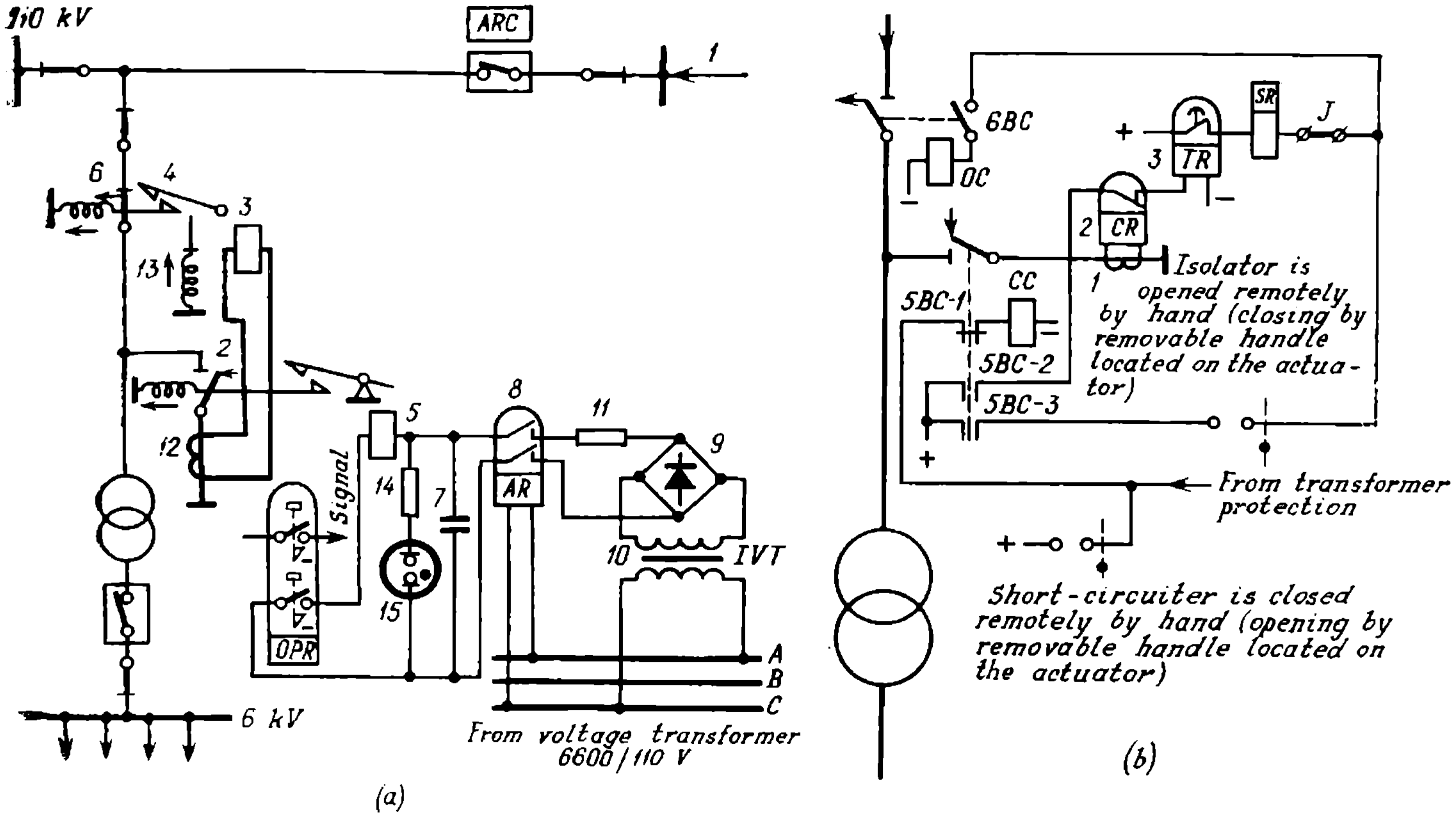

Fig. 12-6. Circuit diagram of automatic and protection units for substations having no breakers on the high-tension side

(*a*) a.c. variant; *1* — supply power system; *2* — short-circuiter; *3* — coil of electromagnet; *4* — tripping device (latch) of isolator; *5* — short-circuiter; *6* — isolator; *7* — capacitor; *8* — auxiliary relay; *9* — rectifier; *10* — voltage transformer; *11* — series resistor; *12* — current transformer; *13* — spring; *14* — resistor; *15* — voltage regulator (tube); (*b*) d.c. variant: *1* — current transformer; *2* — current relay; *3* — time relay

and the current flow in the short-circuiter will start after the operation of the ARC device at substation A. The breaker will be tripped. Recovery of the supply to the intact transformer of the receiving substation can be obtained by using a two-shot ARC device at substation A.

The purpose of time relay *3* in the circuit on Fig. 12-6*b* is to prevent the isolator operating when currents may flow to the faulted place not only from the supply source of the substation A side, but from the synchronous or asynchronous load connected in parallel with the intact transformer.

Tripping the breaker by the protection at the substation A side sharply reduces the current flow in the short-circuiter, which may cause operation of its automatic devices and tripping of the isolator, notwithstanding the fact that currents from the synchronous and asynchronous coasting motors, sup-

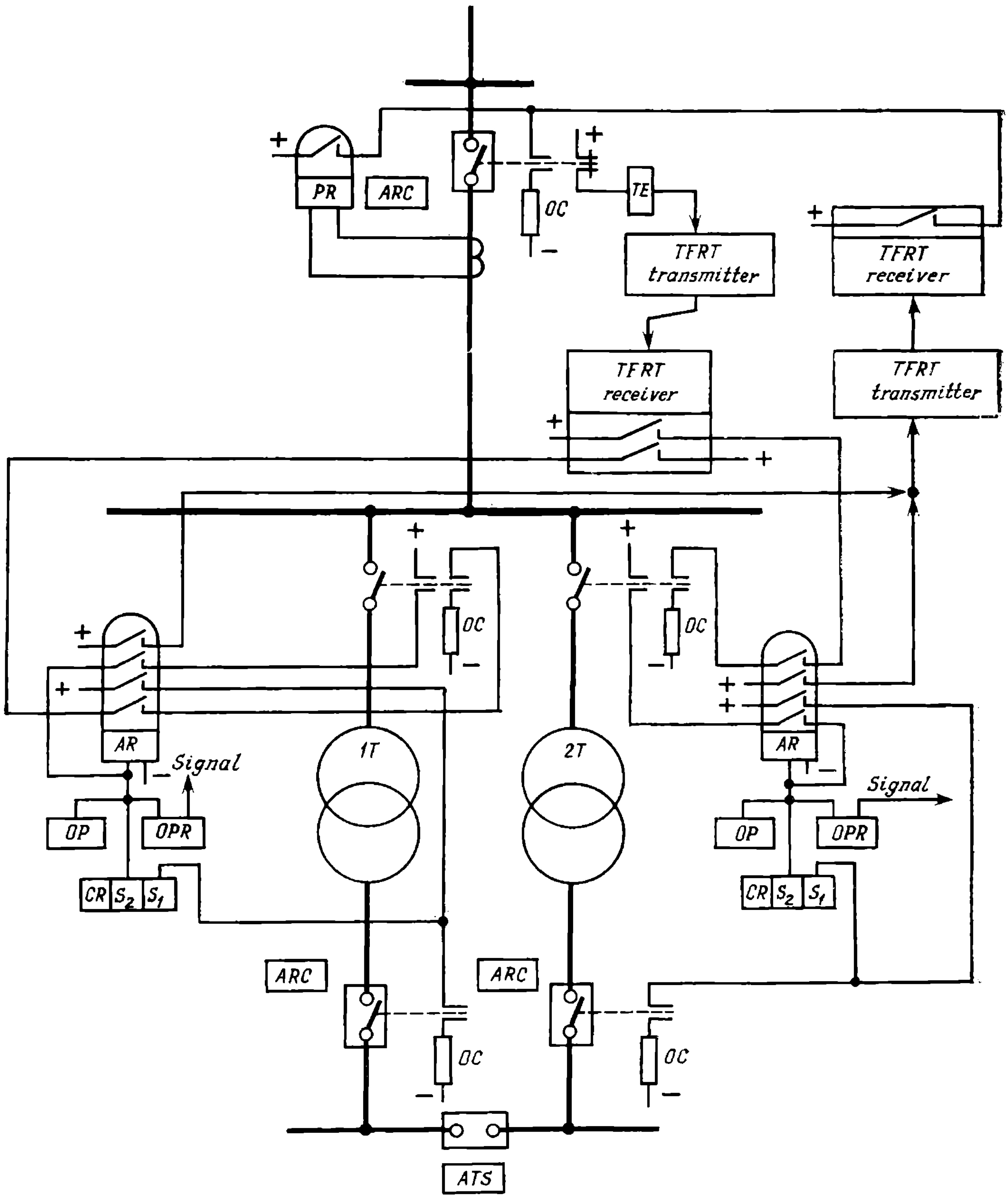

Fig. 12-7. Use of TFRT devices at substations without circuit breakers on the high-tension side of power transformers (explanatory diagram)

plied from the intact transformer whose field is not discharged, continue to flow to the short-circuited point in the faulted transformer. As mentioned previously, to discharge the field of synchronous motors, automatic devices are required which can seize the disconnection of the supply line and transfer the synchronous motor to operation with removed excitation and subsequent resynchronization, the emf decreasing time of the asynchronous motors being 0.5 s. Failure to take these circumstances into account makes the isolator trip an arc which may be responsible for a persisting short circuit and unsuccessful automatic reclosure.

Reliability can be improved by a receiving substation circuit where power breakers substitute the isolators and short-sircuiters. When only one transformer is connected to a transmission line, the entrance of the transformer is in certain instances connected directly to the supply line without an isolator or short-circuiter and even without a disconnecting switch (in equipment sited in atmospheres with chemical fumes). Under these conditions, to trip the breaker at the supply end of the line, remote-tripping devices employing the high-tension conductors or the conductors of the communication cable (devices of the time-frequency remote tripping, type TFRT) are brought into action.

With substations having no breakers from the high-tension side, the use of remote-tripping devices may eliminate the need for short-circuiters or allow them to be treated as a back-up measure. A diagram illustrating the operation of a TFRT device in conjunction with the operation of ARC and ATS devices is given in Fig. 12-7. After tripping the breaker from the side of the supply substation, the transfer of a selective tripping signal to the faulted transformer is delayed by means of a time element *TE* which prevents the disconnecting switch, found in the circuit of the faulted transformer, from tripping an arc sustained by the emf of the coasting loads as stated earlier.

12-5. Simplifying Protective Relaying of Complex System Lines

In order to rapidly clear short circuits in a ring system without employing complicated high-frequency or multi-stage distance protection units, or when these protection units are disconnected for inspection, nonselective operation of simple-type protective relaying devices (examples are current cutoffs, single-stage distance protection units) may be allowed in conjunction with the operation of ARC devices.

The nonselective operation is corrected either by different time settings of the ARC devices installed on the lines of the ring system or by installing ARC devices with a different number of reclosures on the lines of the ring system. In particular, in a circuit section where a fault causes nonselective disconnection of another section furnished with an ARC device no automatic reclosing device may be installed.

We explain this by examples.

The section *AB* (Fig. 12-8) is furnished with protection *2* nonselective with regard to protections *1* of the section *BC* and *5* of the section *BD* (for instance, selective protection *2* is disconnected for inspection and a nonselective protection is installed temporarily).

The nonselective operation can be corrected by several methods.

(1) The ARC devices on breakers *1* and *5* are rendered inoperative. The ARC devices on all the other breakers of the line, breaker *2* included, remain closed. When a fault occurs in section *BC* or *BD*, breaker *2* is tripped simultaneously with the faulted section. The nonselective tripping is corrected by the ARC operation which recloses breaker *2*.

(2) The operating time of the ARC devices reclosing breakers *1* and *2* is diverse. The operating time of the ARC device serving breaker *1* (t_1) is 0.5 to 1 s less than that of the ARC device of breaker *2* (t_2).

If the lines *BC* and *BD* have no high-speed protection units, whose reach covers the entire line, the ARC devices of breakers *1* and *5* accelerate the protection operation after the automatic reclosure. When a fault occurs in section *BC*, this section and breaker *2* are tripped in one operation. The ARC device recloses section *BC*. Breaker *1* is closed in time t_1. If the fault persists, the breaker instantaneously trips. Breaker *2* is closed in time t_2 only after the short circuit has been cleared.

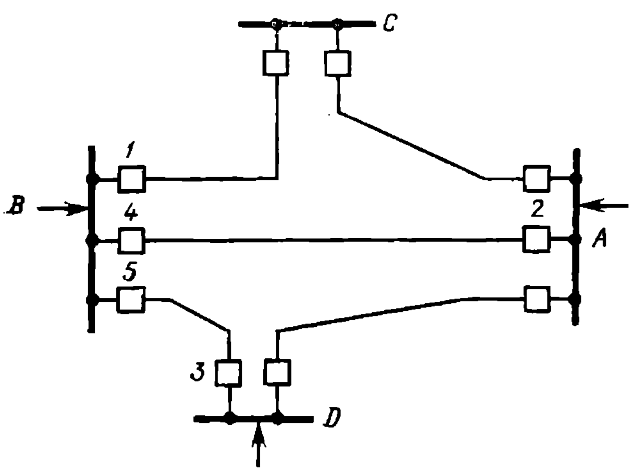

Fig. 12-8. Ring system

The operation of the protection and automatic devices is similar if section *BD* is at fault.

If protection *3* is also nonselective with respect to protection units *1* and *4*, then to correct the protective operation by the second method, the time settings of the ARC devices serving breakers *2* and *3* must be different, that of breaker *2*, for instance, greater than the time setting of breaker *3*. When a fault occurs in section *BC*, breakers *1*, *2* and *3* are tripped. First the ARC device closes breaker *1*, then or simultaneously with breaker *1* breaker *3* is closed, and the third to be closed is breaker *2*. After breaker *3* is closed, if the short circuit persists, sections *BC* and *DB* are simultaneously tripped. Thus, breaker *2* is closed only after the short circuit is cleared. The closing of breaker *2* reestablishes the supply to substation *B*.

(3) The ARC device intended for reclosing breaker *2* is of the two-shot type, while the ARC devices installed on breakers *1* and *5* are of the one-shot type. Correction of a possible nonselective trip is obtained due to the fact that in the case of a persisting short circuit on the line *BC* or *BD*, the faulted lines are disconnected after a one-shot reclosure and do not close any more. Breaker *2*, tripped nonselectively, is reclosed by the two-shot ARC device.

(4) When breaker *2* is automatically reclosed, the ARC device *removes* the accelerated nonselective protection from operation (it had accelerated operation until the automatic reclosure).

The ARC device of breaker *1* promotes the accelerated protection action after automatic reclosure. When a short circuit on line *BC* persists, the ARC device recloses this line simultaneously with the insertion of the nonselective protection, thus breaker *1* quickly trips. The second time, breaker *1* is tripped selectively, as the nonselective protection on breaker *2* is removed by the ARC device.

(5) Sequential ARC operations. After the nonselective tripping of breakers *1* and *2* in the case of a short circuit on line *BC*, the ARC device first closes breaker *2* at a smaller time setting. Some time later after breaker *2* is closed, the same ARC device renders inoperative the high-speed nonselective protection installed on line *AB* from the side of substation *A*. The ARC device next closes breaker *1* in a greater time after the nonselective protection of breaker *2* is removed from operation. Thus, the persisting short circuit on line *BC* is repeatedly selectively tripped.

The above described possibilities of realizing the protection and ARC devices in ring systems make it possible in many cases not to use complicated back-up protection units and not to duplicate involved high-speed protection

units, when they are rendered inoperative for inspection. It is clear, that the method for accomplishing the protection and selection of an ARC device must be adopted depending on the local conditions, possible time settings of the ARC devices, possibility to remove the ARC devices from operation as well as with due consideration to the cirucit configuration.

12-6. Simplifying Primary Connection Circuits and Protective Relaying

In the open ring circuit with simplified protection relaying the ARC devices allow the load to be supplied from two sides, the self-starting of which takes place after an ARC device operation with no disturbance to the production process.

Let us examine a few examples.

1. A substation is supplied over two parallel lines from one power source (Fig. 12-9*a*). Generally, with such lines, overcurrent directional protection units or transverse differential current directional protection units are applied, the four breakers being closed.

The protection system may be simplified if breaker *3* (or *2*) is held disconnected. In this instance, from the side of substation *A* instantaneous protection may be installed, the nonselective operation of which, if necessary, is corrected by the ARC device of breaker *1* (or *4*). When the automatic reclosure at substation *A* is unsuccessful, the ARC device at substation *B* functions thus tripping breaker *2* and closing breaker *3* (or vice versa).

To reduce losses in the circuits, both lines should be connected. Here, breaker *2* of substation *B* may be furnished with "low-rating" protection which instantaneously trips breaker *2* in the case of a short circuit on the circuit sections run from substation *B* to the loads, and on line *3-4*, after the opening of breaker *4*.

Substation *B* is furnished with an ARC device which recloses breaker *2* in a specified time, and with an ATS device which trips breaker *3* and closes breaker *2* when the voltage across substation *B* disappears for a long time (in excess of the time taken by the ARC device to reclose breaker *2*). In the same operation the "low-rating" protection is disconnected.

2. The substation is supplied from two parallel lines, the substation transformers being connected to the lines either through a T or H circuit. Taps connect the substation to the lines. Such circuits are often used to supply power to traction substations.

When breakers *1-2* (Fig. 12-9*b*) or breakers *1-3* (Fig. 12-9*c*) are closed, the line selective protection cannot be easily realized. The protective relaying may be simplified if the receiving substations are supplied through one circuit breaker and if an ARC device exists on the other breaker. In this case, the line protection is accomplished as usual. Its operation is discriminated against short circuits on the secondary side of the power transformers of the substations tapped to the line.

The operation of the high-speed line protection in the case of a short circuit in the power transformers is corrected with the aid of an ARC device installed on the breakers from the side of substations *M* and *N*. If the transformers of the receiving substations are furnished with ARC devices they are started only by the overcurrent (back-up) protection of the transformers. The operating time of the ARC device servicing the breakers is greater than the total time taken to trip the line, in the case of a short circuit on it, and to reclose it by the ARC devices located from the side of substations *M* and *N*.

3. Substation *A* (Fig. 12-9*d*) is supplied from station *M* or *N* and may be also connected into the tie line. If breakers *1* and *2* are normally closed, the usual protection of the lines *MA* and *AN* calls for installation of complicated relaying equipment.

The protection of sections *MA* and *AN* may be to a great degree simplified, if, for instance, breaker *2* is provided with a "low-rating" or is held normally open, substation *A* being furnished with an ARC device (to reduce losses, it is good practice to keep breaker *2*

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closed). In such cases as these, the lines MA and AN may be regarded as lines supplied at one end.

4. Lines M-1-2-3-4-N are long lines connecting power systems M and N (Fig. 12-9*e*). Substation *3* is the boundary between the power systems. If the power systems M and N are paralleled through a tie link, the line protection must take into account possible asynchro-

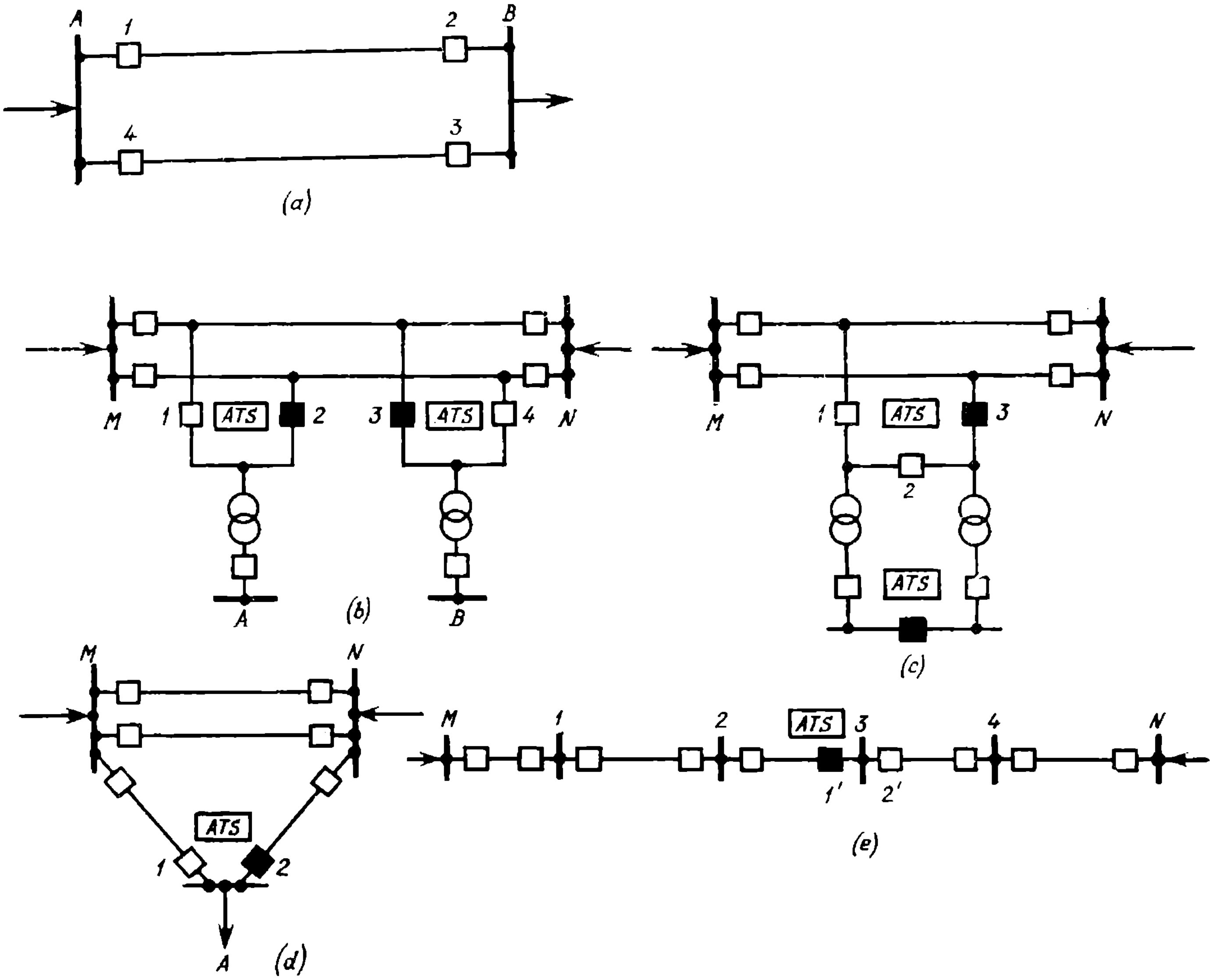


Fig. 12-9. Variants of power supply to circuit sections

(*a*) substation connection to parallel lines; (*b*) same by T-circuit; (*c*) same by H-circuit; (*d*) ring circuit; (*e*) installing ATS device on single intersystem lines

nous operation. If required protection units are not used, breaker *1'* is kept open and is closed by the ARC device only when the power supply fails from the side of substation M or N (for instance, when the voltage across line *2-3* or across the busbars of substation *3* disappears). The entire circuit MN will be switched over to a one-side supply from the power system M, when the busbar voltage of substation *3* fails, and to the supply from the power system N, when the voltage across line *2-3** disappears.

The time taken to automatically reclose the breakers by the ARC device triggered by the undervoltage relay must be greater than the total time for tripping the line from the side

* Such operating conditions may be allowed if the voltage across the terminals of the loads of one-end substations is not below the permissible level, this is possible, but rarely.

of power systems M and N and for reclosing it by the ARC device. The protections of lines MN should be directional.

5. Receiving substations *1*, *2*, *3*... (Fig. 12-10*a*) are supplied from power stations M and N through a "deep" (close to the consumer) service entrance. The step-down transformers

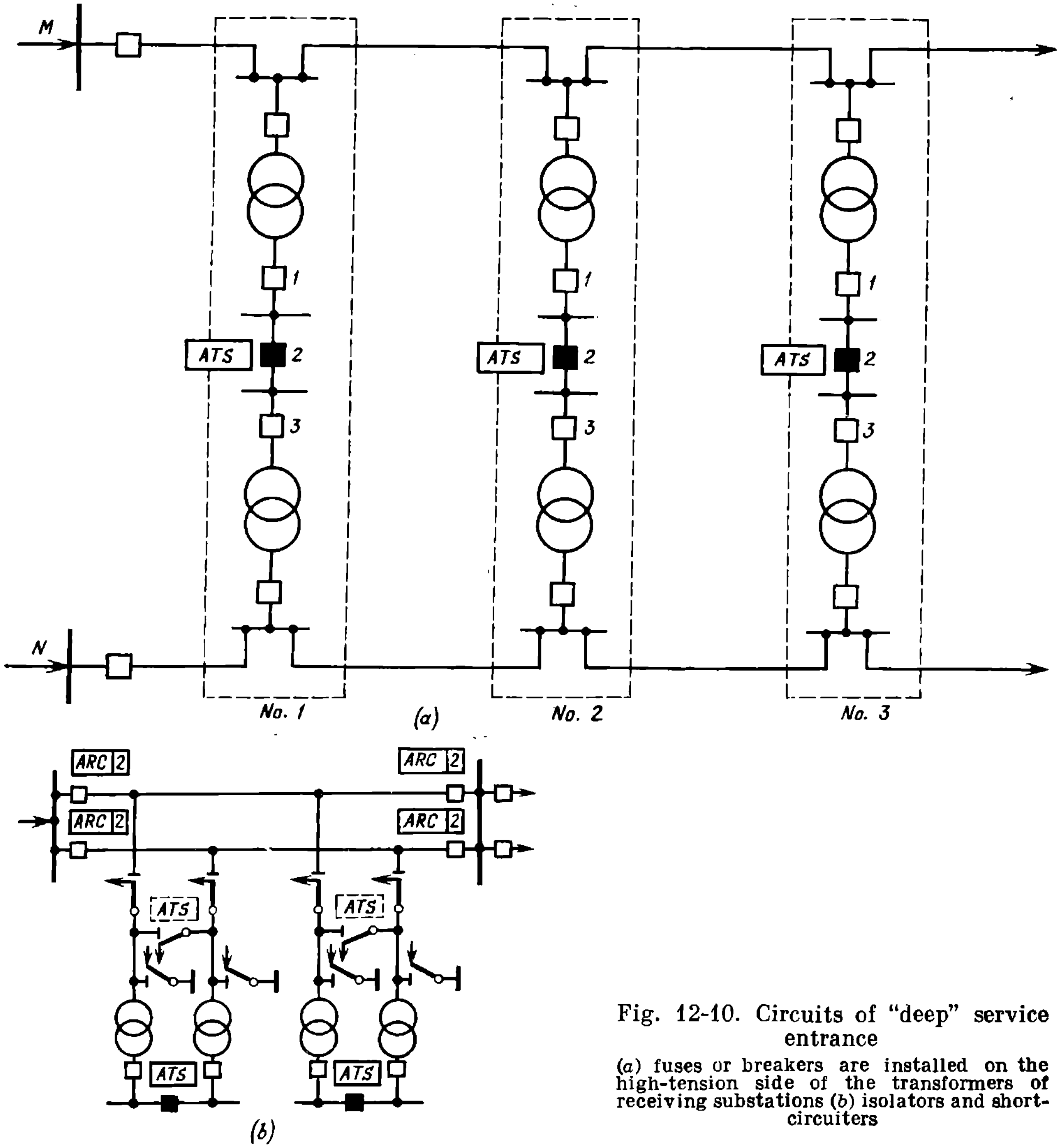


Fig. 12-10. Circuits of "deep" service entrance

(*a*) fuses or breakers are installed on the high-tension side of the transformers of receiving substations (*b*) isolators and short-circuiters

are connected to the tie lines through breakers or high-tension fuses. Installed at the L.T. side of the transformers are ARC devices which trip breakers *1* or *3* in the case of a voltage failure on the corresponding sections of the receiving substations or when no power flows to them and the frequency drops, and reclose breaker *2*.

Overhead trunk lines should be equipped with ARC devices; on cable lines the ARC devices are advisably installed only when there are many substations connected to the line by taps through fuses and also when a delay in the fuse action may cause disconnection of the pilot section of the given trunk from the side of substation *M* or *N*.

If the voltage across the L.T. end of the transformers is 110-380 volts, the breakers are replaced with a.c. automatic cutout devices. The circuit of the ARC device is similar to that shown in Fig. 11-7.

Illustrated in Fig. 12-10*b* is a "deep" service entrance circuit with the use of isolators and short-circuiters at the H.T. sides of the step-down substation transformers. Selective disconnection of a faulted transformer is promoted by the combined operation of the short-circuiter, isolator, line protection, transformer protection and line ARC device.

The supply to the loads connected to the L.T. busbars of the transformers is promoted by the operation of the ATS device closing the section breaker. The operation of the ATS device should be as rapid as practicable, regardless of the operation of the ARC devices installed on the H.T. supply lines.

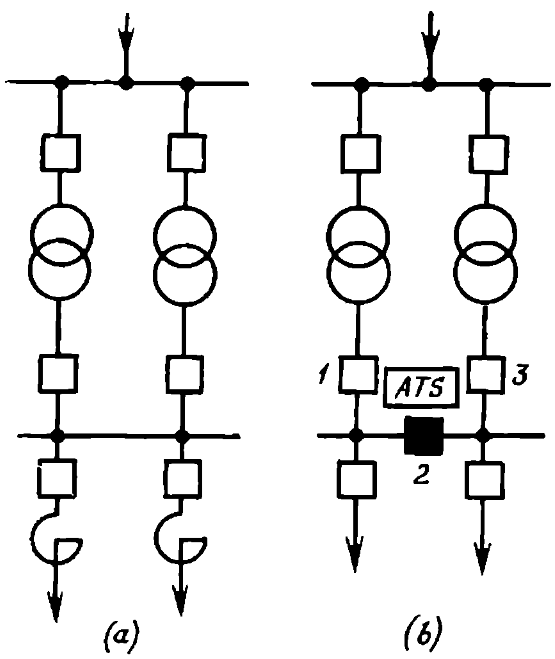


Fig. 12-11. Supply circuits of receiving substations

(*a*) parallel operation of transformers; (*b*) sectionalized power supply to busbars

The use of such a circuit does not ensure reliable service if a synchronous load is connected to the busbars of the consumers' substations and if the consumers employ local power plants of low or considerable output rating (examples are power plants utilizing prod ıction wastes).

If that is the case, when the supply line is tripped due to a short circuit, the short-circuit currents will continue to flow to the point of short circuit from the synchronous load or the generators of the local power plants. The result will be either an unsuccessful automatic reclosure due to a persisting short-circuit arc or asynchronous closure of the synchronous machines.

If a short circuit occurs within the zone between the breaker of the step-down transformer and the isolator, the currents from the synchronous machines of the neighbouring substations will also flow to the point of fault. In this case, the isolator may either fail to open, the result being an unsuccessful ARC from the supply substations, or, if the short-circuit current is, after tripping the supply line, insufficient to hold the isolator closed, it opens and interrupts the current generated by the synchronous machines of the neighbouring substations and thus damages the isolator.

The operation of the ATS devices installed at the L.T. side of the power transformers also becomes more complicated due to the effect of the synchronous machines (motors) connected to the busbars of the standby supply sections. As already mentioned, the ATS operation should be coordinated with the disconnection of the synchronous load or its transfer to operation without excitation[12-4]. The circuits of the ARC device servicing the H.T. lines and the circuits of the ATS devices installed in the L.T. sections should be fulfilled with "waiting" for the voltage across the connections deenergized at the power system side to drop to 40-45 per cent of the nominal value. The generators of local thermal stations should be provided with high-speed sectionalizing protection units isolating these generators with their load share from the busbar sections of the substation whose supply from the power system is interrupted [12-5].

Thus, the use of the circuit shown in Fig. 12-10*b* for supplying important loads is not always advisable.

6. A substation is furnished with two transformers (Fig. 12-11). When these transformers operate in parallel, the short-circuit power is such that reactors must be installed to ensure

the operation of the breakers, or more expensive breakers of higher power rating must be installed. When the transformers operate separately, the short-circuit currents decrease and there is no need to install reactors or more powerful breakers.

Separate operation of the transformers and their use as stand-by units for each other with satisfactory service to the loads is obtained by installing ATS devices on breakers *1-3*. If breaker *1* or *3* is tripped, the ATS device closes breaker *2*.

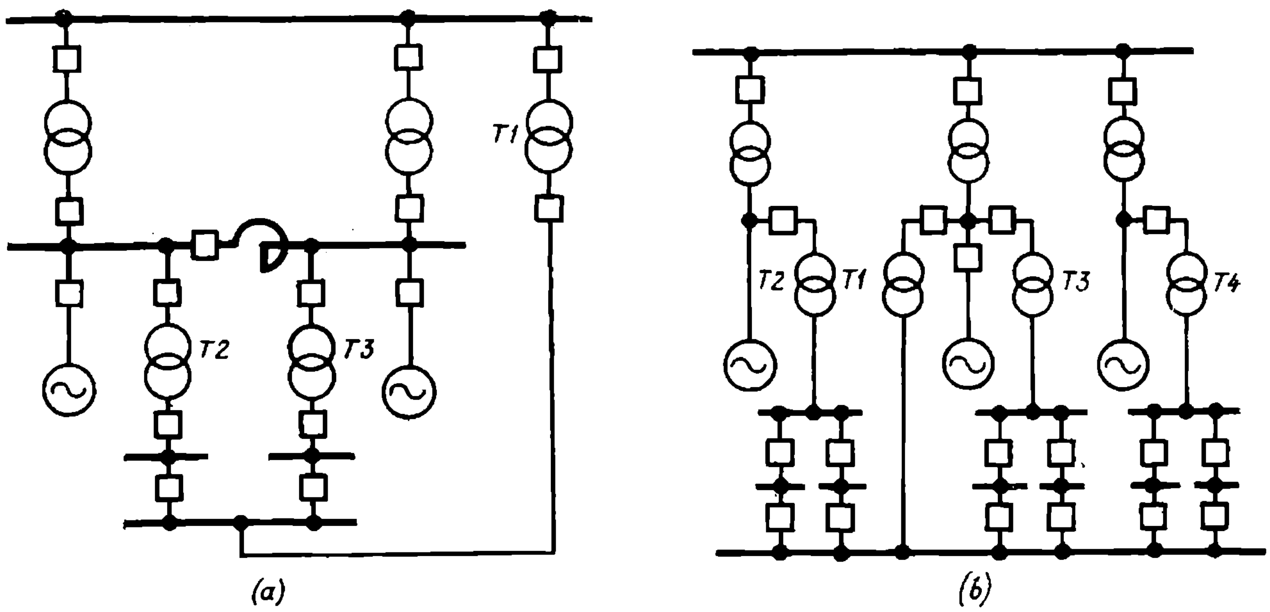


Fig. 12-12. Station-service supply circuits
T1 — stand-by transformer; *T2-T4* — working transformers

7. Shown in Fig. 12-12 are the main power station connection circuits in which sectionalized supply of the station-service busbars is used. A standby transformer may be connected either to the H.T. busbars or to the generator voltage. When the working transformer is disconnected, the ATS device cuts in the standby transformer and transfers the deenergized sections to its supply.

12-7. Step-Down Transformers at Remote-Controlled Substations

If a substation has two transformers working into different sections, the ATS device is allowed to close a section breaker after tripping one of the transformers only when this tripping causes no intolerable overload to the other transformer in operation.

The circuit should be so designed that tripping a transformer by the overcurrent protection causes the operation of the ARC device and prohibits the operation of the ATS device. With the internal-fault protection units, the ATS device in the transformer functions and operation of the ARC device is prohibited. The less important loads of the substation are disconnected to prevent dangerous overloads to the transformer remaining in operation.

When under' normal conditions each transformer is loaded to more than 70 per cent of the nominal rating, it is good practice to disconnect the ATS

device either automatically or remotely and reclose it with the aid of an ARC device after automatic disconnection of the transformer.

In order to prevent the ATS device from possibly reclosing the standby transformer when it is at fault, provision is made for disconnecting the ATS device during the operation of the protection responding to internal faults in the standby transformer. This prohibition is removed by attending personnel after arrival to the substation and elimination of the fault in the standby transformer or after disconnection of the ATS device. Similar prohibition is also applied to the circuits intended for closing the standby transformer by a remote-control unit.

If the working transformer is overloaded and there is a standby transformer which can be connected in parallel to the one in operation, the connection is better performed automatically. After the overload disappears the standby transformer is then automatically disconnected.

The standby transformer may be connected and disconnected by an automatic operator if the peak loads are taken into account in the Load Schedule of the substation. The connection of the transformers may be also governed by the overall load of the substation. If, for instance, the load of the substation rises to 110 per cent of the nominal value of one transformer, the other transformer is automatically switched on. If the overall consumed power decreases below 90 per cent of the nominal value of one transformer, the other transformer is automatically disconnected.

12-8. Automatic Discriminating Redundancy

Automatic discriminating redundancy [11-2] is used for automation of city power circuits, whose loads can accept relatively long (several seconds) interruptions to the service. The loads of a city power circuit are supplied over radial lines through transformer stations. For mutual redundancy purposes several trunk lines are used. A trunk line power supply circuit is shown in Fig. 12-13.

The transformer stations *b* to *e* are supplied at one end from the busbars of substation *a*. Each of the transformer stations may be switched over to another trunk line supply through the transverse links. Under normal conditions these links are isolated at substations *b* to *e*.

Pilot breaker *1* is furnished with a protection unit which responds with the required sensitivity to short circuits occuring on any of the sections *ab*, *bc*, *cd*, and *de*. The operating time of this protection is 0.5 s (discriminated against the operating time of the fuses at the consumers' entrances).

Breakers *2* to *8* are load switches not designed to interrupt short-circuit currents. An automatic discriminating redundancy (ADR) device opens these load switches after breaker *1* is tipped and the trunk line *ae* — deenergized.

The operating time of the ADR devices to trip the load switches is assigned to suit the diagram (Fig. 12-13*b*). The tripping time of even numbers is

$$t_2 < t_4 < t_6 < t_8 \text{ and}$$

the tripping time of the odd number breakers is

$$(t_7 = t_8) < t_5 < t_3$$

The ADR device operates as follows.

When a short circuit occurs on the line, say, at point SC_1 before breaker *1* at the substation *a* is tripped, currents shown in Fig. 12-13*c* by solid arrows

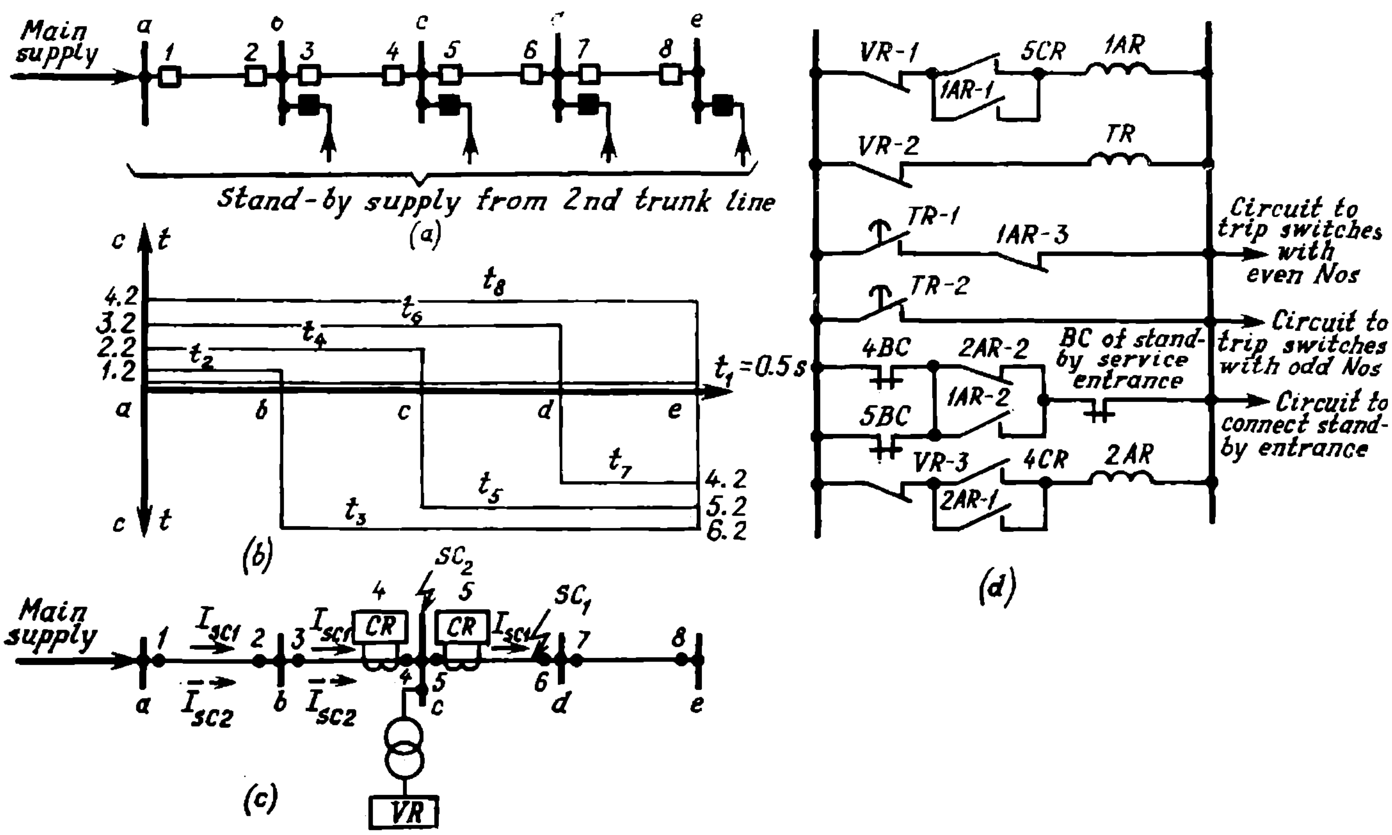


Fig. 12-13. Automatic discriminating redundancy. Normally open switch is shown in black

(*a*) circuit diagram; (*b*) operating time of current protection devices; (c) explanatory diagram; (*d*) schematic diagram of ADR device (for substation c)

flow in the circuit sections. The short-circuit current flow is registered by the ADR devices (with the aid of a relay *1AR*, Fig. 12-13*d*) installed on each of the service entrances of the transformer stations. The relay *1AR* functions if the voltage drop caused by a short circuit is accompanied by the operation of a current relay, i.e., when the contacts *VR-1* and *5CR* close. Relay *1AR* holds itself closed until the voltage is reestablished and the contacts *VR-1* open.

The relay *1AR* operates and breaks the contact *1AR-3* in order to open the tripping breakers with the even numbers. When a short circuit occurs at point SC_1, disconnected in this way are the tripping circuits with time t_2 and t_4.

As the short-circuit current flowed in section *5-6* only to the point SC_1, the relay *1AR* on the ADR device of switch *6* did not function. Thus, switch *6* trips in the time determined by the characteristic t_6 (Fig. 12-13*b*). Switch *5*

is tripped by its ADR device in time t_5. This is done by the time relay *TR* (by the contact *TR*-2 whose circuit is not controlled by the contacts of relay *1AR*).

The breaker of the reserve service entrance is closed by the ADR device when one of the service entrances of the main supply trunk line is disconnected (even or odd, Fig. 12-13*d*) and the service entrance of the reserve supply (controlled by the auxiliary contact *BC* of the reserve service entrance breaker) and the contacts *2AR-2* or *1AR-2* are closed.

The contact *1AR-2* of the ADR devices of the breakers in the circuit carrying the short-circuit current closes. Closed is the contact *2AR-2* in the ADR devices installed in the main supply trunk line sections which carry no short-circuit current (the relay *2AR* functions and breaks the contact *2AR-2*, if the contacts of voltage relay *VR-3* and current relay *4CR* are closed). After the current flow stops, the relay *2AR* holds itself closed with the contact *2AR-1* until the voltage is reestablished.

Thus, the ADR device discriminatingly trips the faulted section with the aid of the load switches (which are not intended for interrupting short-circuit currents) subsequently changing the load to the supply from the reserve trunk line.

When a short-circuit occurs on the busbars of the transformer substation (for instance, at point SC_2), the short-circuit current flow, until the instant breaker *1* trips, is determined by the broken arrows (Fig. 12-13*c*). This differs from the case of a short circuit at point SC_1 (considered above) in that no short-circuit current flows in section *5-6*. Therefore, the relay *5CR* in the ADR device of switch *5* does not function, the relay *1AR* does not operate and the contact *1AR-2* remains open. Since, with a short circuit at point SC_2, the relay *4CR* functioned, the contact *2AR-2* would be opened in time t_5 at the moment switch *5* opens. The load switch of the reserve service entrance of the substation *c* will not be able to close. The faulted busbars will be tripped open by switch *3* in time t_3. The deenergized substations *b*, *d* and *e* would be automatically transferred to a reserve trunk line supply.

The automatic discriminating redundancy method causes long interruptions to the service, a fact which is the main disadvantage of this method of tripping and reserving the sections when they are many in number.

12-9. Conclusions

1. In many instances, the combined operation of the protective relaying, ARC and ATS makes it possible to clear short circuits more quickly, widen the field of application of the ARC and ATS devices and high-speed simple type protection units.
2. It is advisable to use protection acceleration when high-speed protection units are not available. The circuits of ARC devices utilized in the USSR provide for protection acceleration before and after the automatic reclosure. Rather simple sequential automatic reclosures are possible too.

3. After distance connection the accelerated protection time should be such that any reclosure, due to the raised currents resulting from starting the electric motors does not take place.

4. ATS of electrical installations makes it possible to achieve radial supply to the loads with a 100-% reserve supply. The sectionalization of the substation busbars reduces the short circuit currents, thus facilitating operation of the switching equipment and cuts down construction costs.

5. The use of ARC and ATS devices must be coordinated with the appropriate protection units and control devices of the actuators of the asynchronous load breakers and with the automatic devices helping resynchronization of synchronous motors.

6. The combined use of isolators and ARC devices in place of circuit breakers should take into account the type of loads and, in particular, the fact that after deenergizing, the loads continue to maintain for some time the terminal voltage. This is especially true of a synchronous load.

12-10. Review Questions

1. Enumerate the possibilities of simplifying protective relaying devices when ATS devices are applied and the supply is the one-end radial type as compared to the ring power supply system.

2. How can the rapid selective disconnection of a faulted section be ensured by combining the operation of ARC devices with the operation of nonselective protective relaying?

3. What is meant by the expression correction of nonselective operation of protective relaying by means of ARC devices?

4. What is the difference between the protection acceleration before automatic reclosing and the operation of accelerated protection after automatic reclosures?

5. Explain why it is good practice to accelerate the operation of protective relaying devices after any distance closing of a transmission line breaker.

6. What are the phenomena which, when taken into account, limit the possibilities of accelerating the protection operation after the functioning of an ATS device installed on the section breaker of a substation in the presence of asynchronous and synchronous loads?

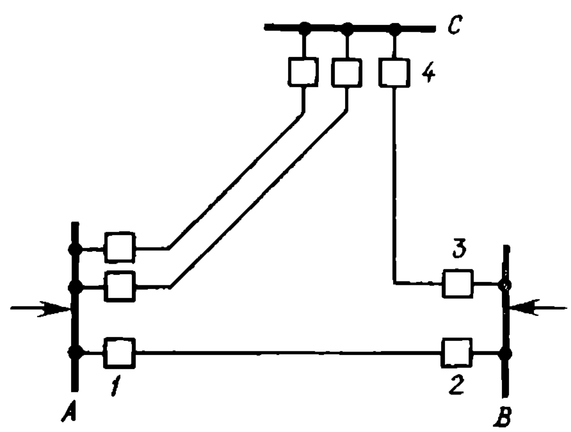


Fig. 12-14. Ring circuit

7. Selective protection unit *1* in the section *AB* (Fig. 12-14) of a ring system is disconnected for repair purposes. What is the method that can be used to preserve rapid clearing of faults on the line *AB* from the side of substation *A* if breaker *1* has its current cutoff closed which is nonselective with regard to the high-speed protection of line *3-4*?

8. How can sequential automatic reclosure be accomplished through the use of an ARC device shown in Fig. 8-4?

9. What is the principle underlying the device for discriminating redundancy of trunk line sections supplied at one end?

10. What are specific features of ATS devices used at remote-controlled substations?

Chapter Thirteen

AUTOMATIC CONTROL ELIMINATING OVERVOLTAGES ACROSS EQUIPMENT

13-1. General

The growth in power station outputs, long distance power transmission and integration of power systems into one super grid for the whole of the Soviet Union means the construction of 500, 750 kV, and more, transmission lines. The one-end disconnection of long lines operating at such voltages causes overvoltages both at the disconnected end and (to a less extent) at the end connected to the supply substation busbars. The terminal voltage of the equipment may exceed the permissible value for its insulation.

To illustrate the operating principles underlying automatic controls which eliminate dangerous overvoltages, we must first find what causes these overvoltages. The electric power transmission lines with distributed inductive reactances and capacity susceptances [13-1] may be presented by T or inverted U equivalent circuits (Fig. 13-1), the legs of which include the lumped reactances. The relationships given below are correct for lines up to 500 km in length. For longer lines, the voltage calculations should be based on the expressions used for circuits with distributed parameters.

The lumped reactance values are determined with the help of the specific inductive x_L and capacity x_C reactances for each kilometer of line length, the resistance being neglected. Let U_{beg} denote the line "beginning" voltage and U_{end} the open "end" voltage. The difference between these voltages is ΔU.

From the diagram in Fig. 13-1*a* it is seen that

$$\Delta U = I_C^a x_L l/2 \tag{13-1}$$

From the diagram in Fig. 13-1*b*

$$\Delta U = I_C^b x_L l \tag{13-2}$$

The currents I_C^a and I_C^a are

$$I_C^a = \frac{U_{end} l}{x_C} \tag{13-3}$$

$$L_C^b = \frac{U_{end}}{2x_C} l \tag{13-4}$$

For both equivalent circuits

$$\Delta U = 0.5 \frac{x_L}{x_C} l^2 U_{end} \tag{13-5}$$

Thus

$$U_{beg} = U_{end} - \Delta U \tag{13-6}$$

$$U_{beg} = U_{end}\left(1 - 0.05\frac{x_L}{x_C}l^2\right) \tag{13-7}$$

hence

$$\alpha = \frac{U_{beg}}{U_{end}} = 1 - 0.5\frac{x_L}{x_C}l^2 \tag{13-8}$$

Figure 13-1*c* shows the ratio U_{end}/U_{beg} as a function of l for the values x_C/x_L corresponding to 500 kV, 50 Hz transmission lines (x_L = 0.297 Ohm/km; $1/x_C$ = 3.71·10⁻⁶ S/km; and x_C = 0.27·10⁶ Ohm·km).

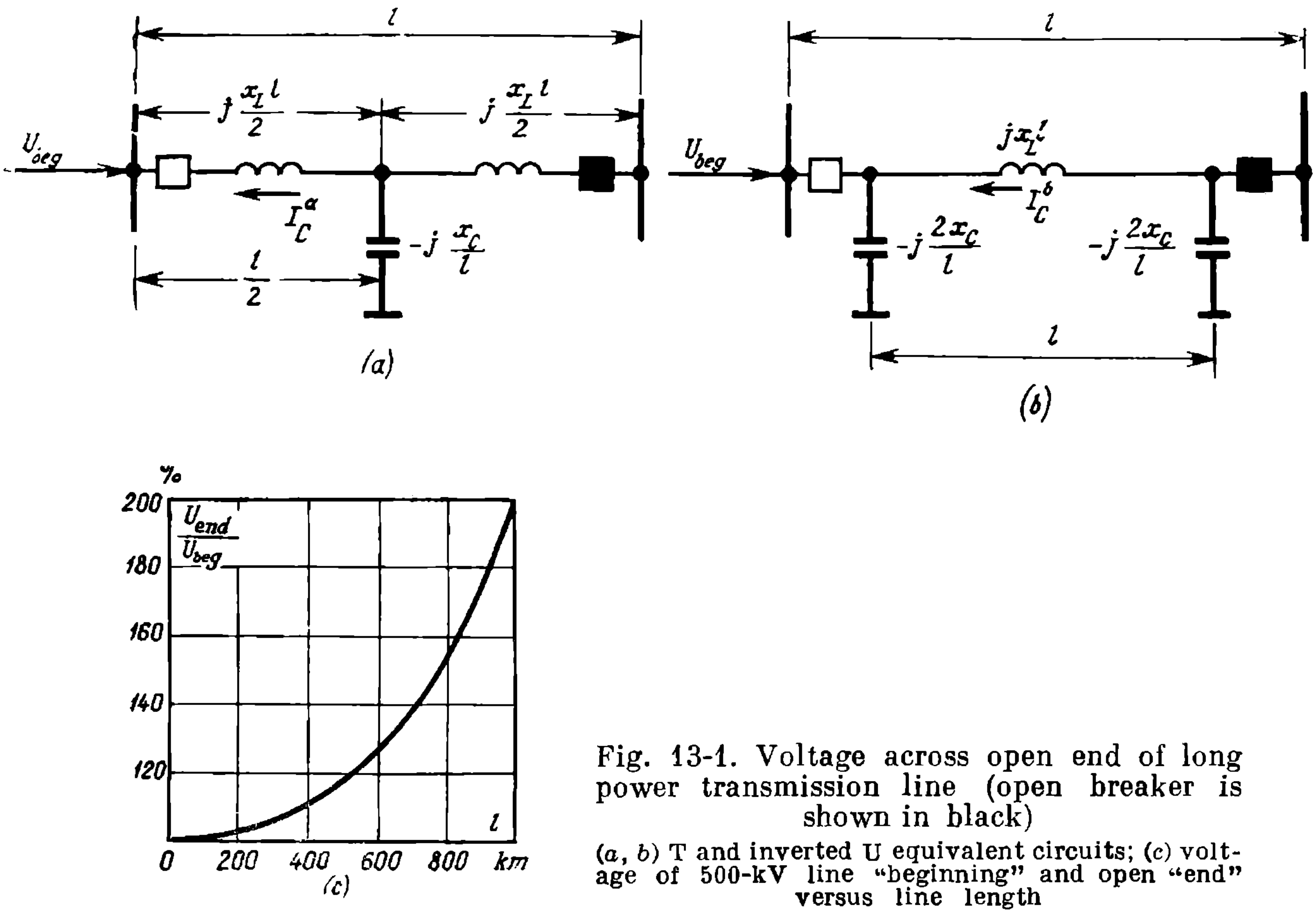


Fig. 13-1. Voltage across open end of long power transmission line (open breaker is shown in black)

(*a*, *b*) T and inverted U equivalent circuits; (*c*) voltage of 500-kV line "beginning" and open "end" versus line length

From Fig. 13-1*c* it is easy to determine the value of the voltage at the open end of the transmission line with respect to the busbar voltage of the supply substation (beginning of line).

If the busbars to which the "beginning" of the transmission line is connected are not the busbars of an infinite-power system, the busbar voltage of the supply substation also rises when the receiving end of the line is tripped. The equivalent circuit in this case has the form shown in Fig. 13-2*a*. The vector diagram is shown in Fig. 13-2*b*.

The busbar voltage of the supply substation is

$$U_{beg}=E_{ph}+I_C x_{syst} \tag{13-9}$$

$$U_{beg}=E_{ph}+\frac{U_{end}}{x_C}\, l x_{syst} \tag{13-10}$$

$$1=\frac{E_{ph}}{U_{beg}}+\frac{U_{end}}{U_{beg}}\, l\,\frac{x_{syst}}{x_C} \tag{13-11}$$

$$\frac{E_{ph}}{U_{beg}}=1-\beta l\,\frac{x_{syst}}{x_C} \tag{13-12}$$

i.e.

$$U_{beg}\geqslant E_{ph} \tag{13-13}$$

When tripping the open long lines carrying the generation, the possibility of an increase in emf of the generators (E_{ph}) should be considered. This may

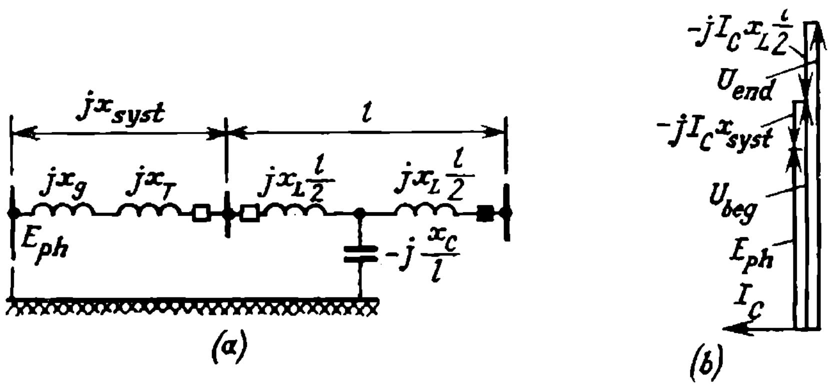


Fig. 13-2. Calculation diagram (*a*) and vector diagram' (*b*) for the case of one-end tripping of long power transmission line (resistance of line and power system is neglected)

occur, first, due to the machine acceleration when the load is discarded (up to 130% for hydroelectric generators) and, second, due to the generator self-excitation effect.

An increase in the generator speed raises the emf of the exciter carried by the rotor shaft and the result is an increase in the voltage across the terminals of the stator winding.

The self-excitation may be explained in a simple way as follows.

When a long transmission line is tripped at the receiving end and it has a generator and a transformer operating as a unit at the supply end, the equivalent circuit may be presented by the circuit diagram in Fig. 13-2*a*.

If the total inductive reactance of the circuit becomes equal to the capacity reactance of the line, i.e., if

$$(x_G+x_T+x_L l/2)=x_C/l \tag{13-14}$$

a condition of resonance arises with a resultant heavy current flow in the stator winding. This overloads the generator.

This overload cannot be eliminated by reducing the excitation manually or by means of a field regulator, for the current flow in the stator circuit is maintained by the residual magnetism in the frame and pole pieces of the machine.

Generator self-excitation is likely to appear when a long transmission line is connected to a low-rating power station, and when the line is disconnected at one end the relationships are close to (13-14).

Let a 225-MW generator working through a 250-MVA transformer be used under emergency conditions for a 505 kV, 500 km line tripped open at the receiving end. Under normal operating conditions of the generator its $\cos\varphi = 0.9$ and frequency $f_0 = 50$ Hz. The line inductive reactance $x_L = 0.297$ Ohm/km, and its capacity reactance $x_C = 0.27 \cdot 10^6$ Ohm·km. For the genereator $x_{dG} = 23$ per cent. For the transformer $e_{sc} = 12$ per cent.

A T-circuit is assumed as the transmission equivalent circuit. If due to a load throwing-off, the generator speed rises the frequency becomes equal to f_1 rather than f_0. The resonance conditions will be when

$$\left(\frac{f_1}{f_0}\right)(x_G + x_T + x_L l/2) = \left(\frac{f_0}{f_1}\right)\frac{x_C}{l} \tag{13-15}$$

For the example under consideration at normal frequency the line capacity reactance

$$x_C/l = \frac{0.27 \cdot 10^6}{500} = 540 \text{ Ohms}$$

line inductive reactance

$$x_L l/2 = 0.297 \cdot 500/2 = 75 \text{ Ohms}$$

generator inductive reactance

$$x_G = \frac{U^2_{in.\,ph}\,(\text{kV})}{S\,(\text{MVA})}\,x_{dG} = \frac{505^2}{250} \cdot 0.23 = 235 \text{ Ohms}$$

transformer inductive reactance

$$x_T = \frac{U^2_{in.\,ph}\,(\text{kV})}{S\,(\text{MVA})}\,e_{sc} = \frac{505^2}{250} \cdot 0.12 = 121 \text{ Ohms}$$

To the condition of (13-15) corresponds the relationship

$$\left(\frac{f_1}{f_0}\right)^2 (235 + 121 + 75) = 540$$

Hence

$$\frac{f_1}{f_0} = \sqrt{\frac{540}{431}} = \sqrt{1.25} = 1.12$$

Thus, for this example, the appearance of self-excitation is clearly seen when the generator speed increases by 12 per cent above the nominal value, i.e., at the frequency of 56 Hz.

Researches show, however [13-3], that the voltage increase due to generator self-excitation appears even before the complete resonance condition.

Along the route of long transmission lines with one-end operation the voltage is mainly reduced (before the closing of a tie line or when it is tripped at one end) by the use of reactors which partially compensate for the effect of the line distributed capacitance. The connection of reactors at both ends of the line is advisable. However, to cut down costs, reactors are generally connected at one of the ends or at intermediate substations. The reactors may be connected either permanently or only when they are required in order to reduce the voltage with a view to preventing damage to the power handling equipment of the substations. Control of the on/off switching operations on the reactors is by automatic devices.

The use of bypassing reactors on the transmission lines, when the breakers of these lines are under single-pole control, may result in resonance effects, when not all the phases of a power transmission section are tripped. Fig. 13-3 shows the circuit formed when one of the line phases is disconnected from both sides. As follows from Fig. 13-3*b*, at certain ratios between the inductive and

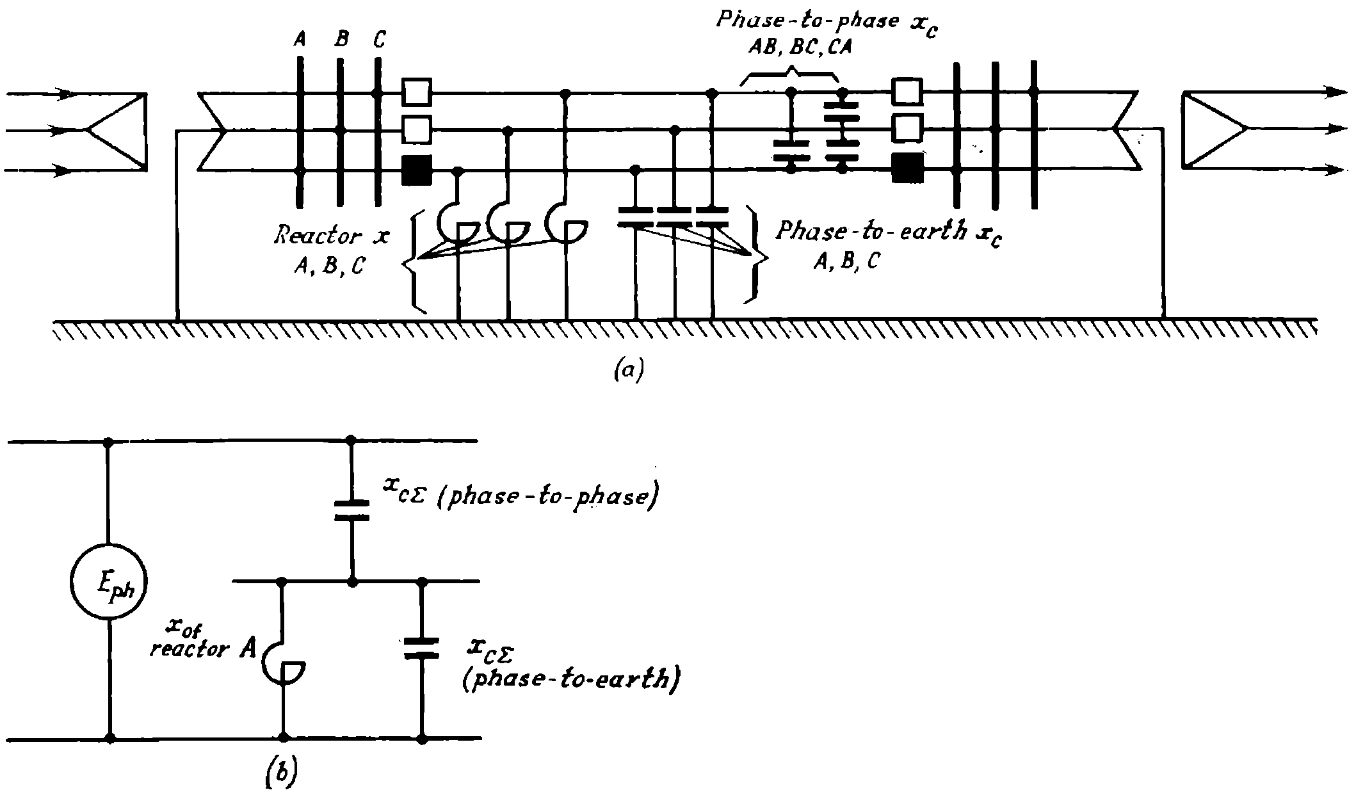


Fig. 13-3. Disconnection of one phase of power transmission line with earthing reactor closed (*a*) and approximate calculation diagram (*b*)

capacity reactances resonance effects may occur at the fundamental or not fundamental frequencies with fairly heavy overvoltages on the insulation of the tripped phase resulting.

The overvoltage protection automatic controls have a setting range from 1.15 to 1.3 of U_n and an operating time of 1.5-2.0 s or more and are isolated against the synchronous swing period and asynchronous operation in order to provide selective operation.

When the voltage rises to 1.4 U_n, the overvoltage automatic controls function instantaneously.

13-2. Overvoltage Automatic Protection Controls

Since one-end disconnection of a long transmission line is not possible by all three phases, the voltage relays are connected to the phase voltages of all the three phases. Only one voltage relay connected to the phase or interphase voltage may be used if there is a special protection against phase-switching

failure. When one of the phases is tripped, whatever the cause, this protection disconnects all the three phases at one of the line ends and an increased voltage results in all the three phases at the supply end of the transmission line and the supply end is disconnected by the three phases, even if the overvoltage automatic protection controls employ only one voltage relay. A protection unit against phase-switching failure is shown in Fig. 13-4.

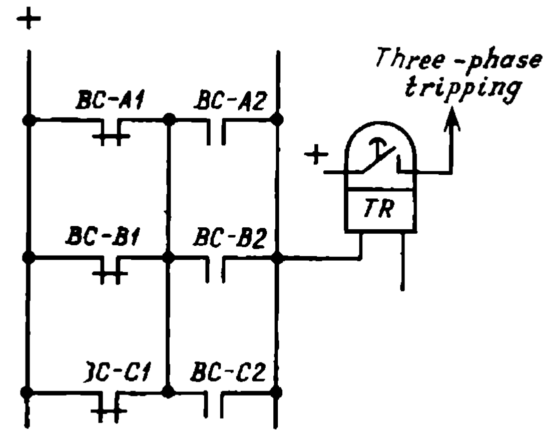


Fig. 13-4. Protection against phase-switching failure

1 — blocking contacts of switch poles which are closed when the phase is tripped; *2* — same contact closed when the phase is closed

When there are several lines outgoing from the substation busbars, the selective disconnection of a line tripped at one opposite end is obtained by installing a one-phase control for reactive power flow at the other end (at the side of substation busbars). The operation of the circuit is clear from Fig. 13-5. If, under the conditions of increased voltage at the substation A, the reactive power flow is directed from N to the A busbars, it means that the line A-N is tripped from the side of substation N. If the reactive power flow is directed from M to A, then the line is disconnected from the side of substation M.

A line may be also tripped at both ends when use is made of a device intended to transmit the tripping signal over the remote-control channel. This method is, however, more complicated.

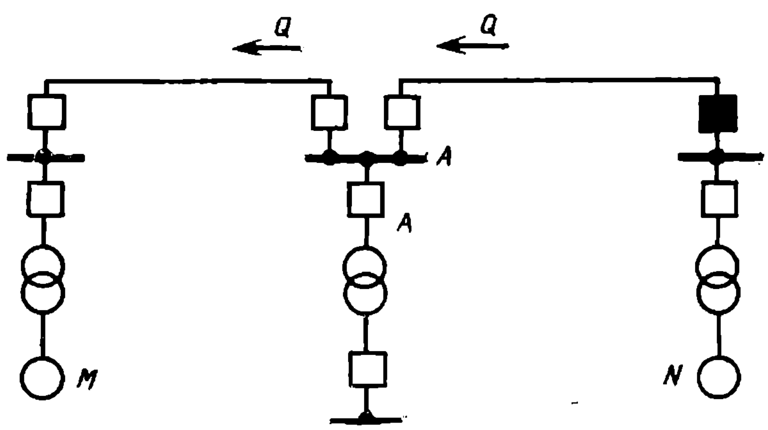


Fig. 13-5. Circuit diagram (open breaker is shown in black)

The operating time of the sets of automatic devices responding to overvoltage is step-like. To take measurements of the reactive power flow in magnitude and direction, a relay, type PБM-274, is used. Its characteristic satisfies the condition

$$T = kU_rI_r \sin \varphi \tag{13-16}$$

The power relay is adjusted so that it functions when the line is disconnected at the opposite end, i.e.

$$Q_{op} = \frac{U_{op.ph}(U_{op.ph} - E_{ph})}{k_r x_{syst}} \tag{13-17}$$

where Q_{op} = phase power at which the reactive power relay functions, MVA
$U_{op.ph}$ = phase operating voltage of the voltage relay, kV
E_{ph} = phase emf, kV
x_{syst} = system reactance (Ohms) from the side of the untripped end of the transmission line, measured from the busbars of the substation equipped with overvoltage automatic protection controls including the reactive power relay in question. The magnitude of the system reactance must correspond to the minimum operating rating of the system
k_r = reliability factor (1.5)

Under normal operating conditions, when carrying only real power, the reactive power relay must reliably remain inoperative. The relay braking moment is produced by displacing the maximum sensitivity angle of the relay a bit so that the load current vector with respect to the voltage vector always ensures the braking effect.

The curcuit of the overvoltage automatic protection controls incorporating a voltage relay and a reactive power relay is shown schematically in Fig. 13-6.

To prevent dangerous overvoltages, the automatic devices must first connect the reactors when they are installed on the transmission line, or at the substation, or if they have been disconnected, in order to reduce the voltage prior to tripping the equipment under protection. To eliminate overvoltages, the operating sequence of the automatic controls is as follows: first, the cause of overvoltage is detected, i.e., the line tripped at the opposite end is determined and after a specified time the line is tripped at the substation end where the overvoltage is encountered. If the tripping is a failure or undesirable, a bypass reactor is placed in the circuit. Another sequence of operations is also possible, i.e., in all instances the reactor is placed into operation before tripping the line. The line is tripped, if engaging the reactor fails to reduce the voltage to the required value.

If the operation of the automatic device produces no desirable effect and the overvoltage persists (an example is a faulted breaker), the equipment under protection is tripped open. For this a breaker operation backup device may be used.

If the reactor is at fault or tripped by the action of the protective relaying, the closing control circuit should be automatically opened and a signal must be sent to attending personnel. After the voltage has been reduced to the rated value and the cause of the trouble eliminated the reactor is usually disconnected manually.

When bypass reactors are connected to 500-kV busbars through step-down transformers or 500/110-kV or 500/37.5-kV autotransformer groups, the disconnection of these groups for some reason makes the voltage in the adjoining

region of the 110-kV or 37.5-kV circuits suddenly drop. Therefore, provision is made in the automatic device for immediate disconnection of the reactors at the 110- or 37.5-kV side when the above-mentioned transformers or autotransformers are tripped. Usually, for this purpose use is made of auxiliary contacts or the contacts or a relay responding to the position of the power switches.

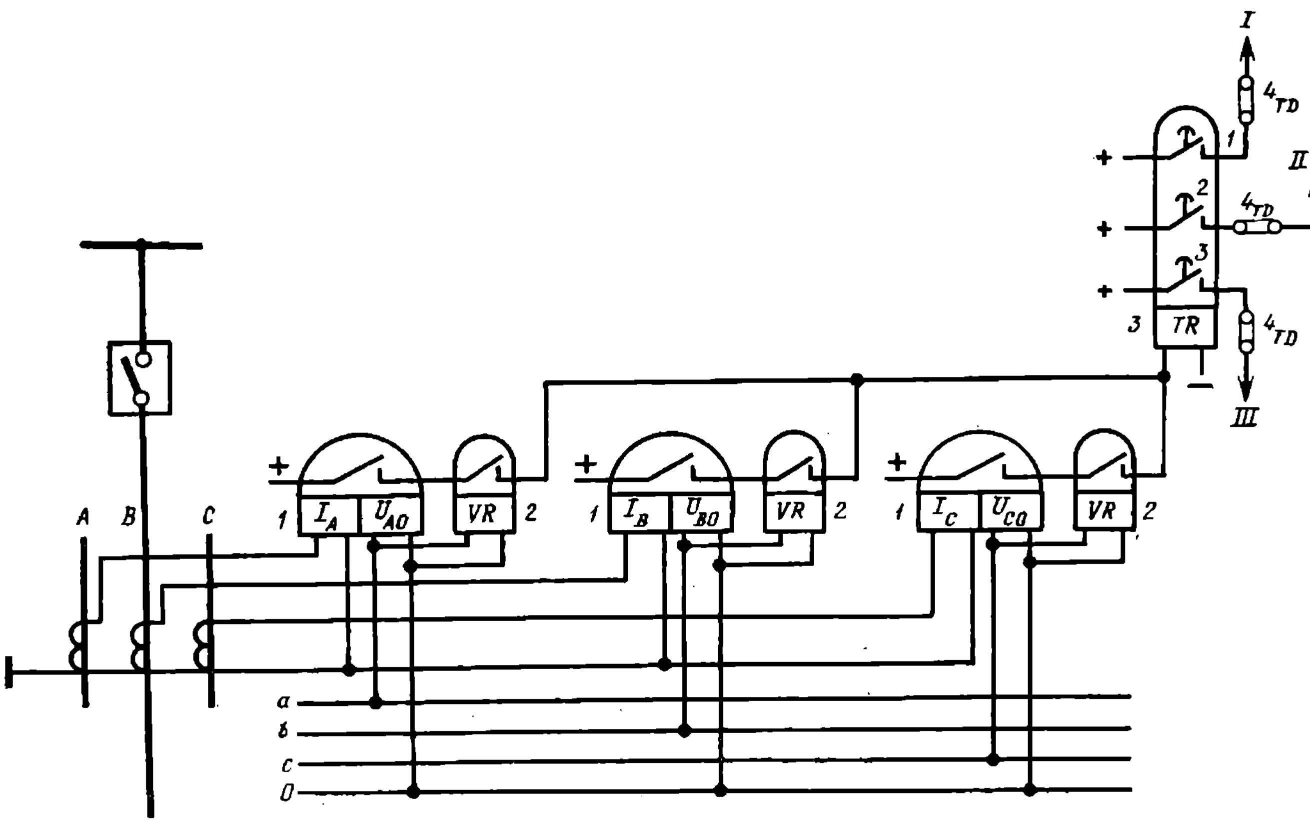


Fig. 13-6. Schematic diagram of automatic devices responding to overvoltage with control of reactive power flow in power transmission line

1 — power relay responding to power $Q = UI \sin \varphi$; *2* — voltage relay; *3* — time relay (*TR-1* — less time; *TR-2* — more time; *TR-3* — still more time); *4* — tripping devices; *I* — circuit to open the line; *II* — circuit to close reactor; *III* — circuit to disconnect autotransformer (if necessary, the sequence of operations may be changed)

The setting of the overvoltage relay is selected by the expression

$$U_{op} = \frac{U_{\max}}{k_{reset}} k_m \qquad (13\text{-}18)$$

where $U_{\max}$ = maximum possible operating voltage
k_m = margin factor (1.05)
k_{reset} = reset-to-pickup ratio of the relay

The smaller the value of U_{op}, the closer the reset-to-pickup ratio of the relay to 1. To obtain a greater reset-to-pickup ratio a special relay design is required as the voltage relays of ordinary types have this ratio equal to 0.9-0.92 even when they are carefully adjusted.

13-3. Increasing the Reset-to-Pickup Ratio of a Voltage Relay

Shown in Fig. 13-7 are some methods for obtaining overvoltage relays with a k_{reset} of 0.98. Figure 13-7*a* shows the connection of an a.c. coil in series with a saturable reactor. Usually, the operation of the reactor takes place near the knee of the magnetizing curve. When the voltage is below the operating setting, the impedance of the reactor suddenly rises, the current in the coil of the relay drops and the relay opens its contacts.

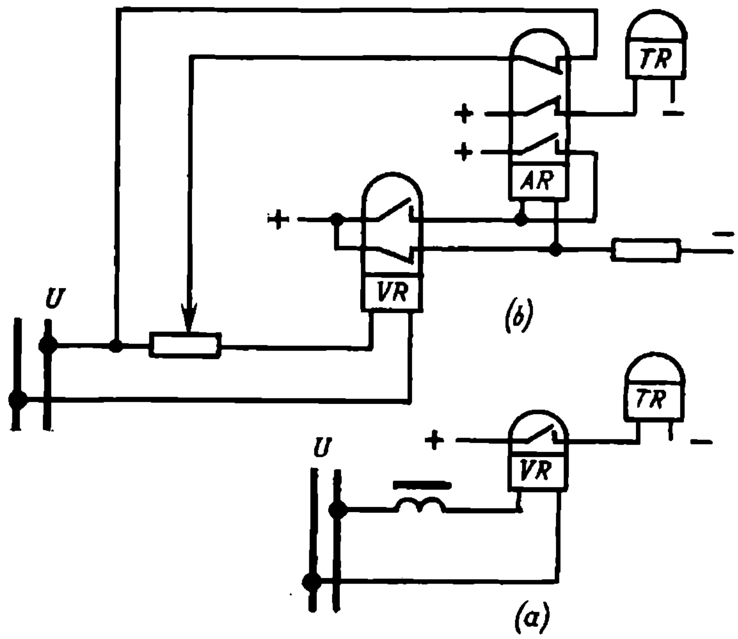


Fig. 13-7. Overvoltage automatic protection controls
(*a*) circuit with additional saturable reactor; (*b*) circuit with series resistor to change the current in relay coil after operation

Shown in Fig. 13-7*b* is a circuit intended for increasing the reset-to-pickup ratio of the relay. An additional resistance is connected in series with the relay coil. After the relay has functioned the resistance automatically increases, since the breaking contact of an output auxiliary relay closes it. To prevent the output relay from vibration, its closing is controlled by the breaking contacts of the voltage relay.

A device responding to a change in the voltage or another electrical quantity and having a reset-to-pickup ratio close to 1 (0.955 to 0.999) can be obtained, if the design is based on measuring the difference between the circuit voltage U_c and the reference voltage U_{ref} of the constant quantity. Multiplying the difference by k_a gives the voltage across the actuator which makes the device function, i.e., the output voltage of the amplifier should equal or be greater than

$$U_{op} = (U_c' - U_{ref})\, k_a \tag{13-19}$$

The device resets, when the circuit voltage becomes equal to $U_c'' < U_c'$,

while the voltage across the actuator is equal to or less than its reset voltage (U_{reset})

$$U_{reset} = (U''_c - U_{ref})\, k_a \tag{13-20}$$

The reset-to-pickup ratio of the device as a whole can be readily determined from the above-mentioned expressions

$$k_{reset.\,d} = \frac{U''_c}{U'_c} = \frac{U_{reset} + k_a U_{ref}}{U_{op} + k_a U_{ref}} \tag{13-21}$$

It is seen from (13-21) that the greater the k_a value, the closer the k_{reset} value to 1.

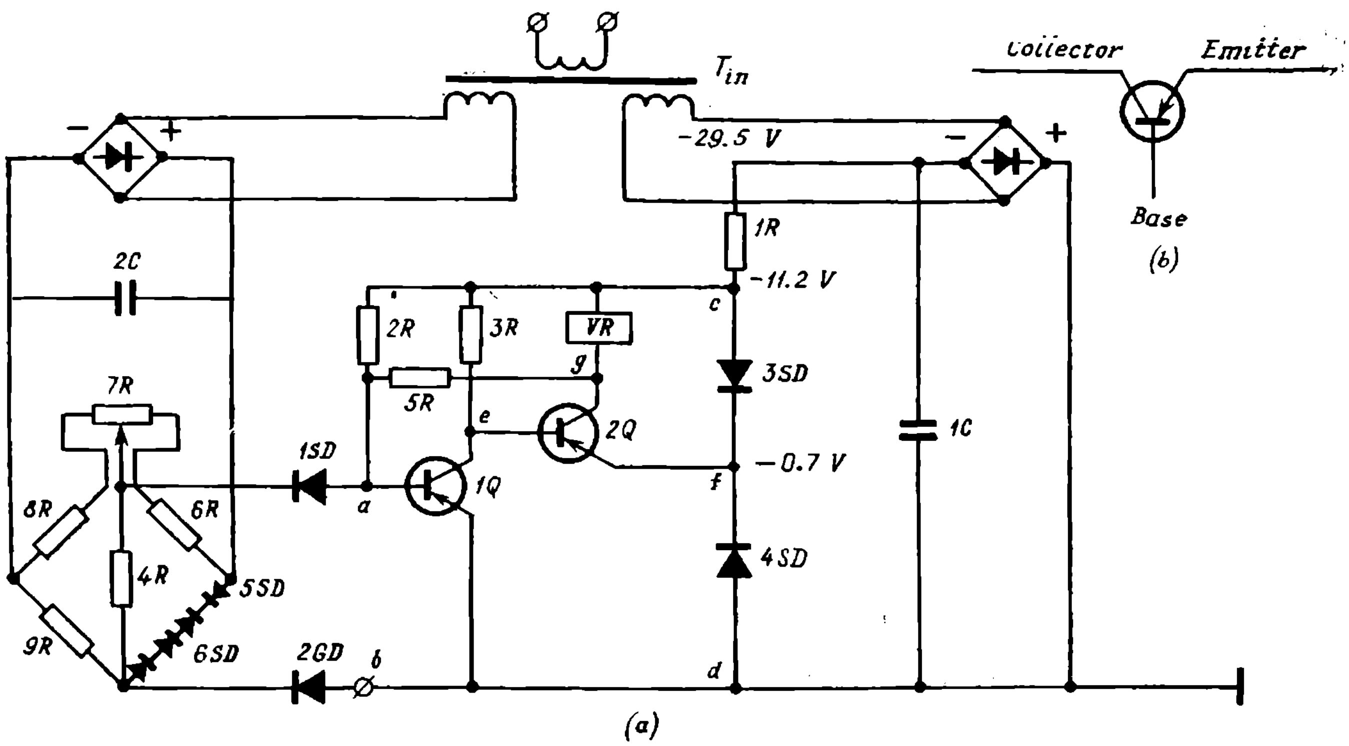


Fig. 13-8. Transistorized voltage relay

(*a*) circuit diagram; (*b*) transistor elements; T_{in} — intervening transformer (input); *1C* — 100 mF; *2C* — 20 mF; *1R* = 1 kOhm; 2 W; *2R* = 110 kOhm; 0.5 W; *3R* = 10 kOhm, 0.5 W; *4R* = 39 kOhm, 0.5 W; *5R* = 470 kOhm, 0,5 W; *6R* = 680 kOhm, 2 W; *7R* = up to 1500 kOhm (variable); *8R* = 3.3 kOhm, 2 W; *9R* = 3.3 kOhm, 9 W; *1SD* and *6SD* — silicon breakdown diodes Д-809; *4SD*, *5SD* — silicon diodes Д-204; *2GD* — germanium diode Д7-Ж; *3SD* — silicon breakdown diode Д811; *1Q* and *2Q* — germanium transistors П-13; *VR* — auxiliary telephone type relay РПН; wire ПЭЛ-0.12, 8000 turns

Shown in Fig. 13-8 is the circuit of a voltage relay based on this principle with an increased reset-to-pickup ratio. This circuit was developed with the use of transistors by K.A. Brinkis for the Latvian power system.

The voltage measurements are taken at the secondary side of the input voltage transformer with the aid of a measuring bridge. One arm of the bridge includes three silicon breakdown diodes *6SD* (type Д-809) and diode *5SD* (type Д-204) which keep the arm voltage constant when the voltage applied to the primary terminals of the input transformer exceeds 35 volts.

The resistors *6R*, *7R*, *8R* and *9R* in the bridge arms and the tap from resistor *7R* are selected so that the voltage drop across resistor *4R* is equal (somewhat less than) to 9 volts when the voltage applied to the primary winding of the transformer T_{in} does not exceed the operating voltage (setting). In this case, the voltage across the silicon breakdown diode *1SD* (type Д-809) is less than the reference voltage and it is cut off (the reference voltage of this breakdown diode is 9 volts). The difference between the applied voltage and the reference voltage serves as the control voltage for an amplifier utilizing a flip-flop circuit including transistors *1Q* and *2Q*. The control voltage U_{ab} is applied to the input of transistor *1Q*. The amplifier is supplied from the node points *c* and *d* of the circuit. The voltage U_{cd} is taken from a potentiometer consisting of resistor *1R*, silicon breakdown diode *3SD* and silicon diode *4SD*. The potentiometer is supplied through a rectifying bridge from the secondary winding of transformer T_{in}. The potential distribution among the node points of the potentiometer is shown in Fig. 13-8.

The breakdown diode *3SD* maintains a constant voltage between the collector and emitter of transistor *2Q* equal to 10.5 volts. The potential at point *c* (—11.2 V) is lower than that at point *a* (—9.0 V), for which reason the current flow is from point *a* to point *c* through resistors *2R* (110 kOhms) and *5R* (470 kOhms). The base potential of the transistor *1Q* (point *a*) appears lower than the emitter potential of this transistor (point *b*) and thus the transistor is conducting a current $i = i_{2R} + i_{5R}$.

Carried by the collector of transistor *1Q* is the current i_{3R}. The potential at point *e* is higher than the potential at point *f*. The transistor *2Q* is nonconducting and its emitter-to-collector resistance is high. The resistors *2R* and *5R* are selected so that the relay *VR* does not operate under these conditions. If the voltage drop across the resistor *4R* becomes greater than 9 V, which is the case when the voltage applied to the primary terminals of the transformer T_{in} is greater than the operating setting, the current in the breakdown diode *1SD* starts to flow towards point *d*. This raises the potential at point *a*. The transistor *1Q* ceases to be conducting, the potential at point *e* becomes less than the potential at point *f* and the transistor *2Q* starts to conduct. The result is an increase in the potential at point *g*; this decreases the current i_{5R} flowing in the resistor *5R* and adds more to the potential at point *a*, i.e., decreases the current which makes the transistor *1Q* conduct.

The use of resistor *5R* ensures a positive feedback, causing the amplifier to operate like a relay (in steps). In this operation the transistor *2Q* becomes fully conductive and causes the relay *VR* to operate through the emitter-collector circuit of transistor *2Q*. If after the above-described relay operation the input voltage of the transformer T_{in} decreases below the setting, the operation of the circuit is the reverse, i.e., the transistor *2Q* becomes cut off, the relay *VR* resets, and the transistor *1Q* starts to conduct.

The secondary voltages of the input transformer are rectified by the full-wave rectifiers connected each into one of the secondary windings of the transformer T_{in}. Capacitors *1C* and *2C* smooth down the rectified voltage and filter away the a.c. component. The ambient temperature effect on the operation of the relay is reduced as follows.

The diode *5SD* in the arm of the measuring bridge is connected in opposition to the breakdown diodes *6SD*. With an increase in the ambient temperature, the reference voltage of the breakdown diodes *6SD* rises, while the voltage across the opposing diode *5SD* lowers, which partially compensates for the change in the temperature. Partial temperature compensation is achieved similarly when the diode *4SD* and the breakdown diode *3SD* are in opposition.

The temperature compensation of the emitter-base circuit of the transistor *1Q* is partially effected through connecting the diode *2SD* in the forward direction. Simultaneously, this diode prevents a heavy positive input signal of the measuring bridge from coming to point *b* of the amplifier.

A voltage relay having a reset-to-pickup ratio equal to unity may be realized through the use of tunnel diodes in a way similar to the sensing element of the voltage regulator changing the transformation ratio of the step-down transformers [2-4]. Since the operating time of the overvoltage automatic devi-

ces exceeds one cycle, each instant the current (voltage) passes the zero point the tunnel diode stops conducting, this ensures the reset-to-pickup ratio of the device to be equal to unity. This circuit of a transistorized relay is more perfect than the variant described above.

Often used in the overvoltage automatic protection controls is a voltage relay, type PH-58, having $k_{reset} = 0.95$[13-3]. The circuit of this relay is shown in Fig. 13-9. The sensing element R is in the form of a moving iron relay having $k_{reset} = 0.8$. The increase in k_{reset} is due to the fact that connected in series with the coil of relay R are the breakdown diodes Bd forming the reference voltage. The purpose of the rectifier Re is to rectify the voltage being taken for measurement from the secondary winding of the intervening transformer T. The pickup settings are controlled by the potentiometer r_1 and by tapping the winding of the intervening transformer. The control range is from 50 to 100 volts. The operating time of the overvoltage relay ranges from 0.1 to 0.15 s.

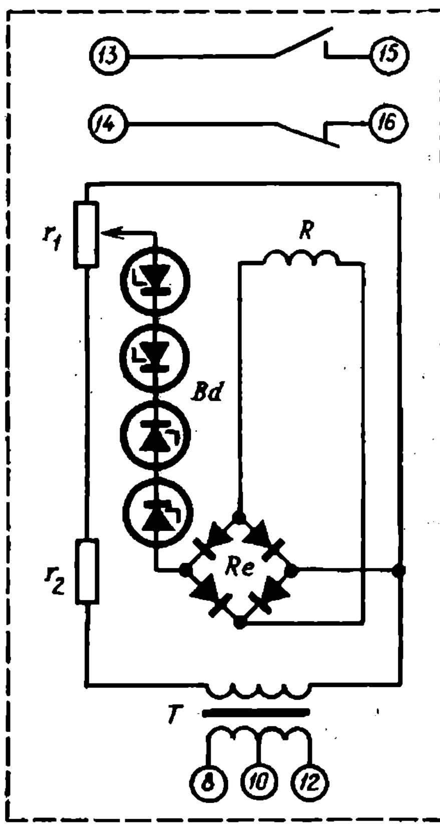


Fig. 13-9. Circuit of voltage relay, type PH-58

13-4. Conclusions

1. The construction of a.c. high-tension (750 kV, and more) power transmission lines over long distances and their possible one-end disconnections require automatic controls to eliminate prolonged overvoltages dangerous to the basic equipment of the substations.

2. These overvoltages are eliminated either by tripping the three phases of the transmission line from the side of the substation, to which the line remains connected after its opening at the opposite end, or by engaging a reactor at the substation. A reserve measure is to disconnect the equipment.

3. The detecting elements of the automatic devices responding to overvoltages must possess a high reset-to-pickup ratio. Methods are developed which make it possible to obtain 0.95 to 0 999 reset-to-pickup ratios. The use of tunnel diodes makes it possible to have $k_{reset} = 1$.

4. To obtain selective operation of the overvoltage automatic protection controls, a step method of time delay selection combined with the use of a reactive power flow relay is used. This relay is a sine-type power relay.

5. An increase in the sensitivity of the overvoltage relay may be obtained by connecting the relay to the voltage at the open end of the transmission line. The opposite end of the line is disconnected with the aid of a remote-tripping device.

Another possibility is the use of a phantom circuit, i.e., the substation busbar voltage compensated for by the voltage drop, due to the current in the

line disconnected at the opposite end, is applied to the measuriug element of the automatic device.

13-5. Review Questions

1. What is the purpose of the automatic overvoltage protection?

2. What are the methods of making the automatic overvoltage protection controls operate selectively on long power transmission lines?

3. What are the causes of overvoltages at substations from which long power transmission lines are run?

4. What is the purpose of bypassing reactors? How do the automatic devices connecting the reactors operate when the voltage increases?

5. What are equivalent circuits of long power transmission lines with distributed constants? What is the possibility of taking voltage measurements at the open end of the line with the use of a phantom circuit (by the compensation method)?

6. A 500-kV, 400-km power transmission line is connected to the busbars of a substation. When the line is disconnected at the opposite end, the reactance measured at these busbars is equal to 2 Ohms in one instance and to 20 Ohms in another instance. In which instance will the busbar voltage of the substation be greater?

7. A 500-kV substation is linked to various parts of the power system by three power transmission lines, 350, 250 and 300 km long. How can automatic overvoltage protection which permits the line tripping at the opposite end be realized at this substation?

8. What are the methods of obtaining a higher k_{reset} value for the detecting element used in the automatic overvoltage protection controls? How can one obtain $k_{reset} = 1$?

9. In the presence of bypassing reactors what is the cause of possible dangerous overvoltages on a phase of a three-phase long extended power transmission line disconnected at both ends?

10. Silicon breakdown diodes are connected in series with the coil of an overvoltage relay. The breakdown diodes and the coil are opposite-connected. Explain the thought behind such connection.

Solution. For silicon breakdown diodes, the volt-ampere characteristic has the form shown in Fig. 13-10. If a reverse voltage is applied to a silicon breakdown diode, then up

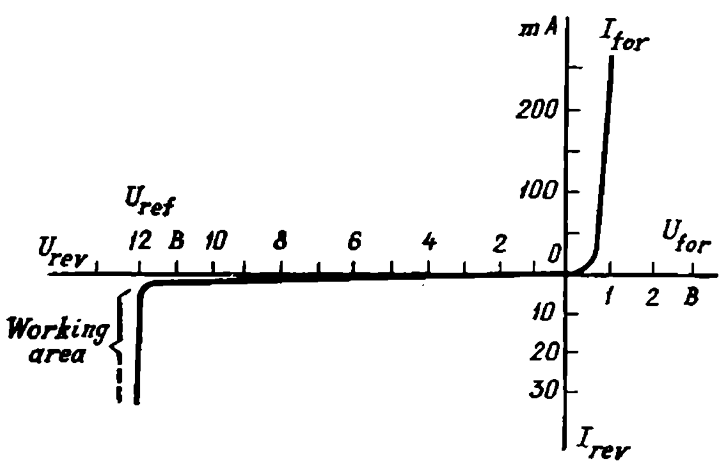


Fig. 13-10. Volt-ampere characteristic of breakdown diode

to a certain value of the reverse voltage the current will not increase and it suddenly rises when it reaches a certain (reference) value, the diode voltage, however, remaining constant. In contrast to ordinary type diodes, the sudden increase in the current due to the application of a reverse voltage causes no nonreversible breakdown or damage to the silicon breakdown

diodes. When the voltage imposed upon a silicon breakdown diode decreases, its resistance recovers and the diode attains the rectifier properties. These properties of silicon diodes, when connected in opposition, make it possible for a constant a.c. voltage to be sustained across the terminals of a diode stack. At one polarity of the a.c. sine curve the voltage is sustained constant by the breakdown diodes connected in one direction and at the other polarity, by the breakdown diodes connected in the other direction. A sharp change in the resistance of the breakdown diodes, when the applied voltage is changed, promotes accurate functioning of the output element and eliminates vibration of its contacts (when the reverse voltage drops below the reference value, the resistance sharply increases and the current in the circuit under control decreases).

11. What must be the ratio between the values of the reference voltage across a breakdown diode stack of two silicon diodes connected in the forward and reverse directions and the operating voltage of the relay R with its coil connected in series with the mentioned breakdown diodes (Fig. 13-9) in order to make the reset-to-pickup ratio ($k_{reset.\ d}$) equal 0.95. The reference voltage of each of the silicon diodes is —12 volts (Fig. 13-9). The reset-to-pickup ratio of relay R ($k_{reset.\ r}$) is 0.8.

Solution. The operating voltage of the overvotage protection automatic control

$$U_{op.\ d}=U_{ref}+U_{op.\ r}$$

where U_{ref} = reference voltage across the breakdown diode stack of two silicon diodes which equals $2\cdot 12 = 24$ volts

$U_{op.\ r}$ = operating (pickup) voltage of relay R

The reset voltage of the automatic overvoltage protection control

$$U_{reset.\ d}=U_{ref}+U_{reset.\ r}$$

where $U_{reset.\ r}$ = reset voltage of relay R.

The reset-to-pickup ratio of the automatic control

$$k_{reset.\ d}=\frac{U_{reset.\ d}}{U_{pickup.d}}=\frac{U_{ref}+U_{reset.\ r}}{U_{ref}+U_{pickup.\ r}}$$

hence

$$k_{reset.\ d}=\frac{\dfrac{U_{ref}}{U_{pickup.\ r}}+k_{reset.r}}{\dfrac{U_{ref}}{U_{pickup.r}}+1}=\frac{\alpha+k_{reset.\ r}}{\alpha+1}$$

$k_{reset.\ d}$ is assumed to be equal to 0.95, hence

$$0.95=\frac{\alpha+k_{reset.\ r}}{\alpha+1}$$

If $k_{reset\ .r}$ = 0.8 then $0.95\alpha+0.95=\alpha+0.8$, i.e., $0.15=0.05\alpha$, $\alpha=3$

Since U_{ref} = 24 volts,then $U_{pickup.\ r}$ = 8 volts.

As mentioned previously in (13-4) the setting of the automatic device is controlled by the potentiometer r_1 and not by changing the pickup setting of relay R, as it may at first appear without analysis of the circuit operation.

Another method to determine k_{reset} of the automatic device may proceed from the following prerequisites. Assume that the k_{reset} value of relay R is low, say, 0.2. This, however, does not reduce the k_{reset} value of the automatic device, if the breakdown diode is cut off when its terminal voltage falls to the value $U_{in.\ d} = 0.95\ U_{ref}$ (at 11.5 volts).

The instant the silicon diode is cut off, its resistance sharply rises and the current carried by the diode and the coil of relay R connected in series with it suddenly decreases. The result is the relay R resets, i.e., the armature of the movable electromagnet drops out.

12. Is it possible to use a PH-58 relay for undervoltage protection?

Chapter Fourteen

AUTOMATIC RECORDING OF ELECTRICAL VARIABLES IN DISTURBANCES

14-1. General

For successful operation of a power system it is essential for the load dispatcher to know the load of the tie links and the switching conditions of individual links involved in the generation and distribution of electric power. For this purpose, use is made of remote-control apparatus and an assemblage of information machines. Such devices, however, are relatively slow in operation and do not give adequate analyses of the electrical processes taking place at fault origination and during short circuits. These processes are decisive in analysis of the power system operation under emergency and after-fault conditions and in estimation of operation of the protective relaying and automatic devices.

From the nature of changes in the currents and voltages before the fault, during the fault and after the fault, it is also possible to examine the stability of parallel operation, type of short circuit, sequence of tripping or closing individual terminations and determine the fault distance. The latter is very important to organize rapid repair work on long lines [14-1, 14-2].

Automatic oscillographs are available from the industry with or without before-fault recording and recording instruments using an accelerated paper feed during disturbances.

Many power systems are furnished with ammeters and voltmeters fixing the starting electrical magnitudes in short circuits.

From these instruments and calculations the load dispatcher determines the fault distance along the transmission line.

The model H-11 automatic oscillographs are widely used with the records being made on camera film (cinema film). Eight measuring loops may be used simultaneously to record the various electrical quantities. This oscillograph model has two disadvantages: the need to develop the film and it is sometimes necessary to enlarge the oscillograms. To save film, special devices designed for automatic starting operate the oscillograph for short periods (0.1 to 0.15 s) in the case of short-time disturbances or for longer periods (0.5 to 10 s) when the abnormal operation is more prolonged.

The oscillograph, model H-13, makes the oscillograms directly on a paper photographic tape giving also the date and time of the disturbances. Up to 12 electrical signals may be recorded simultaneously.

The automatic fault-recording oscillograph, model HO22, continuously records a process on a magnetic drum. Under normal operating conditions the record is subsequently erased. If a fault occurs before the erasing operation, a camera records the processes taking place prior to the fault, during the fault and after the fault. The complete revolution time of the drum is about 0.3 s. No speed of response requirements are placed on the triggering device of the oscillograph (which is the case with the starting devices of H-11 and H-13 oscillographs). The HO22 oscillograph has 12 channels to record electrical quantities on a camera film[14-3].

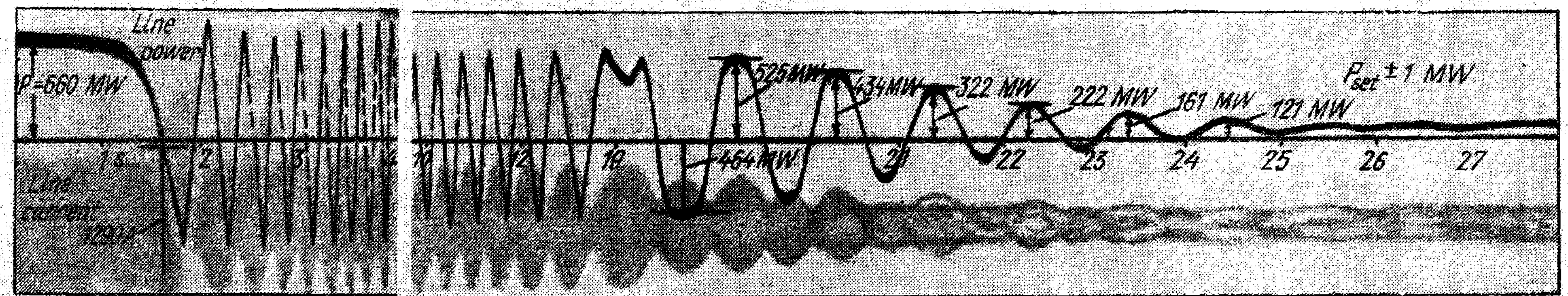
Electrical process records made by the instruments can be seen from Fig. 6-1. Figures 6-1*a* and *b* illustrate records of changes in the frequency, made by a recording frequency meter operating without accelerating the paper tape feed. Figure 6-1*c* shows similar recording with the tape feed accelerated.

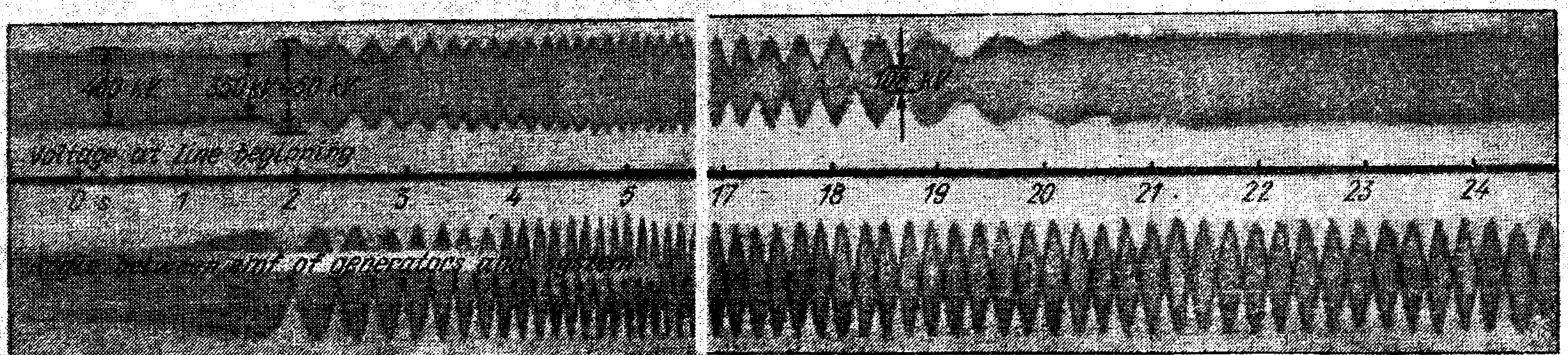
Electrical process records made by oscillographs are shown in Fig. 14-1. The oscillograms shown were taken when determining the steady-state stability limits, by gradually increasing the real power flow, on the 400-kW single-circuit transmission line run from the Volga Hydroelectric Power Station to Moscow.

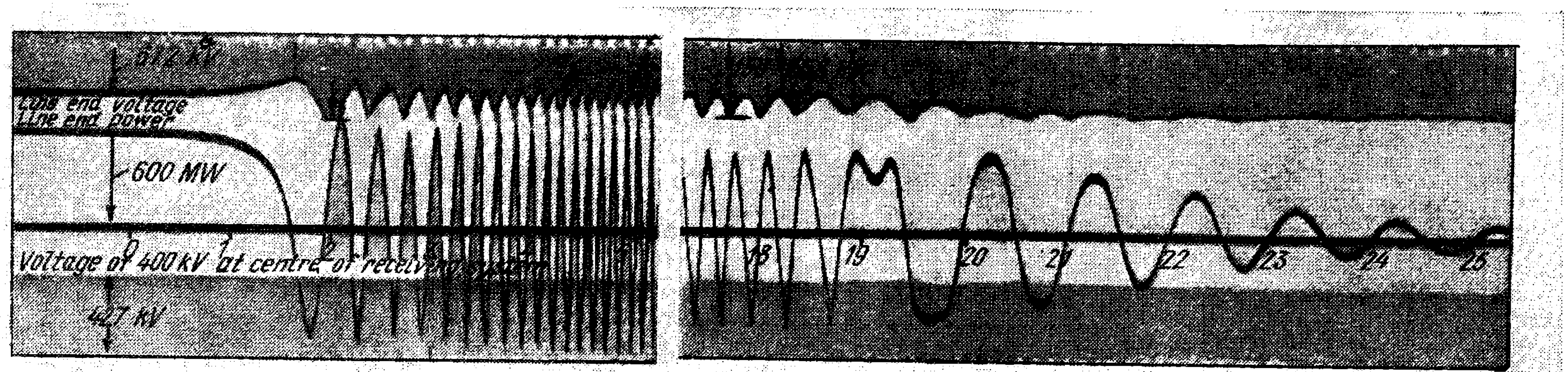
Oscillogram interpretation. Before the synchronism was disturbed, the voltage at the beginning and end of the power transmission line gradually decreased and the angle between the emf of the station generators and the receiving system increased. The current flow in the line was also growing. Within the angle zone $\delta_{12} = 180\text{-}360$ degrees, the sign of the real power carried by the power transmission line reverses and this change accounts for the braking of the receiving system generators and the sudden acceleration of the station generators. Thus the current and voltage beat frequency increases. If during the first period the generators fall out of step the swing cycle was 2 s, the subsequent cycle period falls to 0.12-0.1 s. Under the action of the turbine speed governors the accelerated hydroelectric generators of the station were gradually slowing, while the generators of the receiving system were gaining speed (on the expense of reserve power); the oscillation cycle of the current, voltage and power was increasing. With each revolution of the emf vectors the generators of the Volga Hydroelectric Power Station and the receiving system first underwent an increase in the power, and then a decrease.

To facilitate resynchronization, during the Volga Station experiment six generators of the eight working into the power transmission line were manually disconnected, this caused a decrease in the equalizing current amplitude and power surges. The two generators in operation resynchronized at the 19th second from the beginning of the experiment. The resynchronization moment is indicated by a saddle on the real power flow oscillogram. The saddle shape curve is due to the fact that during resynchronization the angle δ_{12} starts decreasing and oscillates about a setup value (without reaching 180 degrees) becoming either positive or negative relative to it, at an ever decreasing amplitude. Thus, synchronous swings appear, decaying in time. In the experiment, they disappeared in 8 seconds (at the 27th second from the start of the experiment).

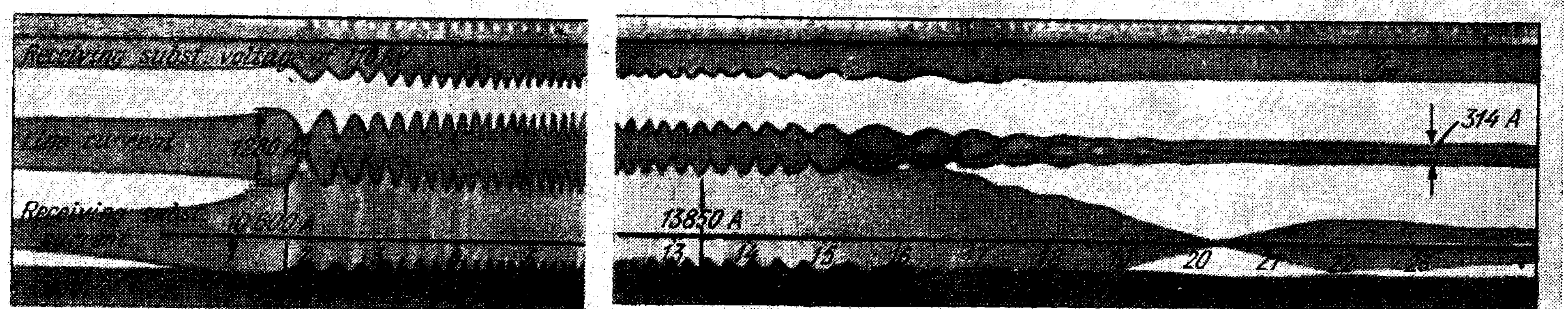
Shown in Fig. 14-1*d* is a stator current oscillogram of a synchronous capacitor installed at the receiving substation of the power system. During the experiments, this synhronous capacitor was pulled out of synchronism both with respect to the generators of the Volga Hydroelectric Power Station and the generators of the receiving system. The synchronous capacitor resynchronized after the power transmission current swings had decayed (at the 27th second from the beginning of the experiment). After self-synchronization the half-cycle duration of the stator current swings was 6 seconds (from the 19th to the 25th second) and 2 seconds (from the 25th to the 27th second).


Line power
P=660 MW
Line current
525 MW
434 MW
322 MW
222 MW
161 MW
121 MW
464 MW
$P_{set} \pm 1$ MW
1 s
2
22
24
25
26
27
(a)


Voltage at line beginning
0 s
1
2
3
4
5
17
18
19
20
21
22
23
24
(b)



(c)



(d)

Fig. 14-1. Oscillograms of processes at disturbances to synchronism during experiments on determining the steady-state stability of single-circuit transmission line, the Volga Hydroelectric Station to Moscow. (*a*, *b*) sending end of the line; (*c*, *d*) receiving end of the line)

14-2. Automatic Starting Devices for Oscillographs

The operating principle of a starting device can be understood from Fig. 14-2. The starting device is activated at asymmetric short circuits by a backward-sequence current or voltage relay (I_2 or U_2), and during symmetric short circuits and swings (or asynchronous operation) an undervoltage relay *VR* is used. This relay also functions at phase-to-phase short circuits on those phases to which it is connected.

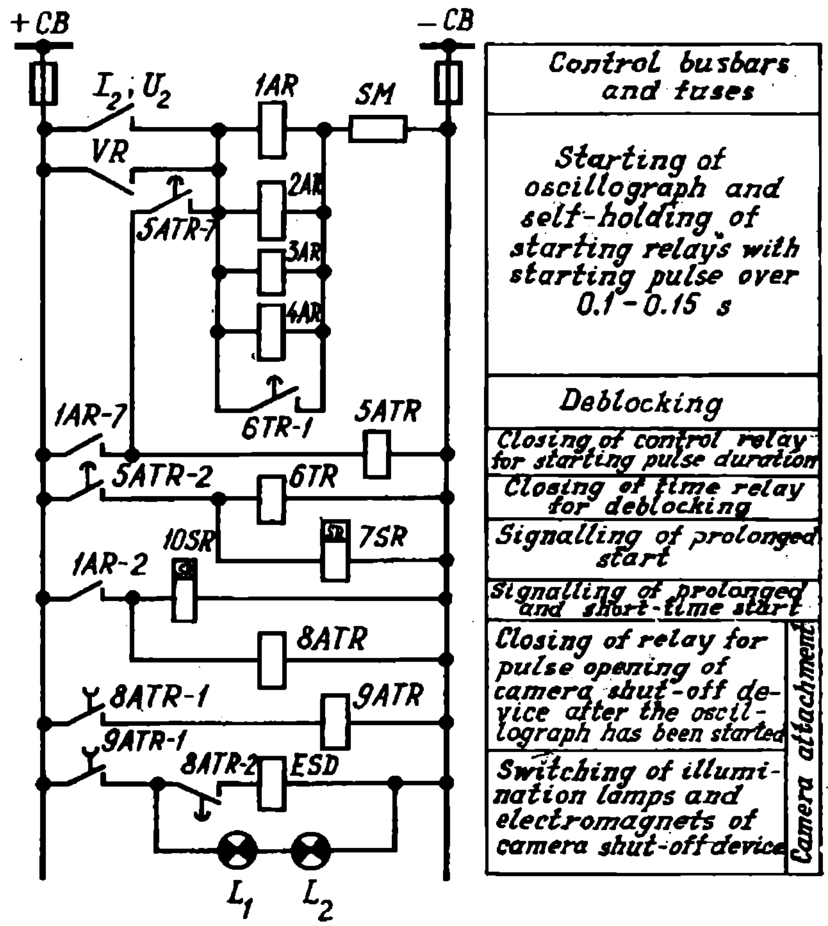


Fig. 14-2. Schematic diagram of device for oscillograph automatic starting (the circuits from the contacts of relays *2AR*, *3AR*, and *4AR* to close the electromagnets of couplings and shut-off devices and to connect vibrators are not shown)

In short-time abnormal operations, as during the operation of lightning arrestors, the coil circuits of auxiliary relays *1AR*, *2AR*, *3AR* and *4AR* are closed for a short time. The relay *1AR* is used as an auxiliary unit to close the relays *5ATR* and *8ATR* (by the contacts *1AR-1* and *1AR-2*). The other relays are used to engage the electromagnets of the oscillograph couplings and shut-off devices and to connect the vibrators to the circuits of the magnitudes being recorded or control lighting circuits used in the photographing.

At disturbances lasting more than 0.1-0.15 s, the contacts *5ATR-1* close to make the relays *1AR* through *4AR* lock themselves, even if the relay I_2/U_2

or *VR* has reset. The oscillograph is actuated until the operating time of relay *6TR* is over. The coil circuit of this relay is closed by the contact *5ATR-2* in order to ensure recording of the after-fault operation. The time setting of relay *6TR* may be adjusted within the range of 0.5 to 10 s. The relays *1AR* through *4AR* reset because their coils are bypassed by the contact *6TR-1*.

However, if due to blown fuses the contacts of relay *VR* or U_2 remain closed longer than the time setting of relay *6TR*, the oscillograph will not be switched on repeatedly, for the coil of relay *5ATR* and hence the coil of relay *6TR* will be energized.

Thus, the device saves recording paper.

In order to orient each oscillograph starting, time provision is made for photographing a clock dial. With H-11 oscillographs, the clock is fitted above the instrument casing. The clock pictures are taken at the end of each starting. The camera attachment includes two relays *8ATR* and *9ATR* with reset delay, two illumination lamps L_1 and L_2 and a shutter controlled by electromagnetic shut-off devices *ESD* which, when engaged, open the camera slot under the clock dial.

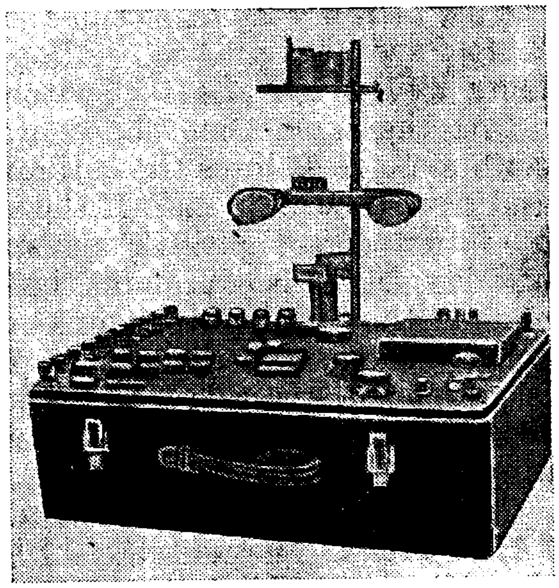


Fig. 14-3. H-11 oscillograph with lamps and clock to record time

When the oscillograph is started and relay *1AR* functions, contact *1AR-2* closes relay *8ATR*. Its contact *8ATR-1* makes the coil circuit of relay *9ATR*, while its contact *8ATR-2* opens the circuit of the electromagnets of the shut-off device used in the camera attachment. The contact *9ATR-1* feeds the operating current to the camera attachment and turns on the illumination lamps.

After the oscillograph has started and relay *1AR* reset, the coil circuit of relay *8ATR* opens and 0.1 to 0.15 s later this relay opens the coil circuit of relay *9ATR* and closes the electromagnetc circuit of the camera shut-off device. Since the drop-out time of the *9ATR* armature is 0.1 to 0.15 s, the camera shutter will open for this time with the illumination lamps lit up to take the picture of the clock dial. After this time, the armature of relay *9ATR* drops out, the shutter closes and the camera attachment returns to the initial position. Thus, the device is ready for the next operation.

Operation of the oscillograph starting device is indicated by signalling relay *7SR* (prolonged start signalling) and *10SR* (short-time and prolonged start signalling). For the external view of the H-11 oscillograph with a camera attachment see Fig. 14-3.

Available from the industry is the УПО-1 automatic starting device with auxiliaries intended for starting both the H-11 and H-13 oscillographs.

A backward-sequence voltage relay, zero-sequence voltage relay and interphase voltage relay serve as the elements responding to disturbances. All these relays are transistorized and possess a high reset-to-pickup ratio [14-3]. The operating circuit diagram of the УПО-1 device is given in Fig. 14-4. Under normal conditions the device is supplied from a 110-220-V source of operating current. In this case, relay *2AR* is excited and contact *2AR-1* is closed. All the other relays of the device are deenergized.

When a fault occurs, relay *1AR* closes and its contact *1AR-1* opens the coil circuit of relay *2AR*. When the armature of relay *2AR* drops out, the contact *2AR-4* switches on the oscillograph motor (in a forcing manner) and the contacts *2AR-3* and *2AR-5* switch on the light to its full voltage.

At the same time the contact *1AR-2* closes the relay-follower *3AR*. The contact *3AR-3* closes the coil circuit of relay *4ATR* which is delayed in pick-up and reset (for 55-60 ms). If the starting element operates for a short time (as the operation of a lightning arrester) and resets before the contact making time of relay *4ATR* is complete, the circuit resets, the motor of the tape feed mechanism of the oscillograph stops and the supply to the illumination circuit ceases. Only a very small amount of photographic paper is consumed. If the starting is prolonged, the relay *4ATR* has time to function, the contact *4ATR-1* opens the coil circuit of relay *2AR* and this relay will not be able to stop the recording process until the end of recording cycle is reached.

The contact *4ATR-2* holds the coil of relay *4ATR* closed until the contacts *2AR-2* break. The contact *4ATR-3* prepares the closure of relay *1TR*. Through signalling relay *1SR* the contact *4ATR-4* sends a start signal (OSCILLOGRAPH START).

At the end of the faulty operation and the reset of relay *1AR*, the contact *1AR-2* opens the circuit of the *3AR* coil. The contact *3AR-4* closes relay *1TR*. Two to five seconds later, the sliding contact *1TR-1* makes and closes the coil of relay *5AR*. The latter locks itself with the contacts *3AR-5* and *5AR-2* and its contact *5AR-1* supplies power to the coil of relay *2AR*. This relay functions and breaks the circuit of the oscillograph motor and illuminator.

After the contact *3AR-3* breaks, the armature of relay *4ATR* drops out with a 0.2-0.4 s delay. As a result, the circuit of the clock illuminator opens only after the mentioned time (by means of contact *4ATR-7*). The delay makes it possible to take the picture of the clock dial after the full stop of the tape feed mechanism motor. The photographing time is determined by the time of the stop contact *1TR-2* and operation of relay *6AR*: the contacts *6AR-1* and *6AR-2* open the coil circuits of relays *1TR* and *5AR*, respectively; the contact *6AR-3* completes the motor armature circuit for the time required to move the photographic tape with the clock picture (0.35 to 0.6 s).

If another fault occurs before the device is reset relays *1AR* and *3AR* refunction. Contact *3AR-4* opens the coil circuit of time relay *1TR* and it resets. The oscillograph stops operating only after the time relay *1TR* closes its final contact. When the contacts of the starting relays are closed for a long time (a blown fuse in the secondary circuit of the voltage transformer) the time relay *1TR* will not repeat its operation. In this instance, the time relay *2TR*, having

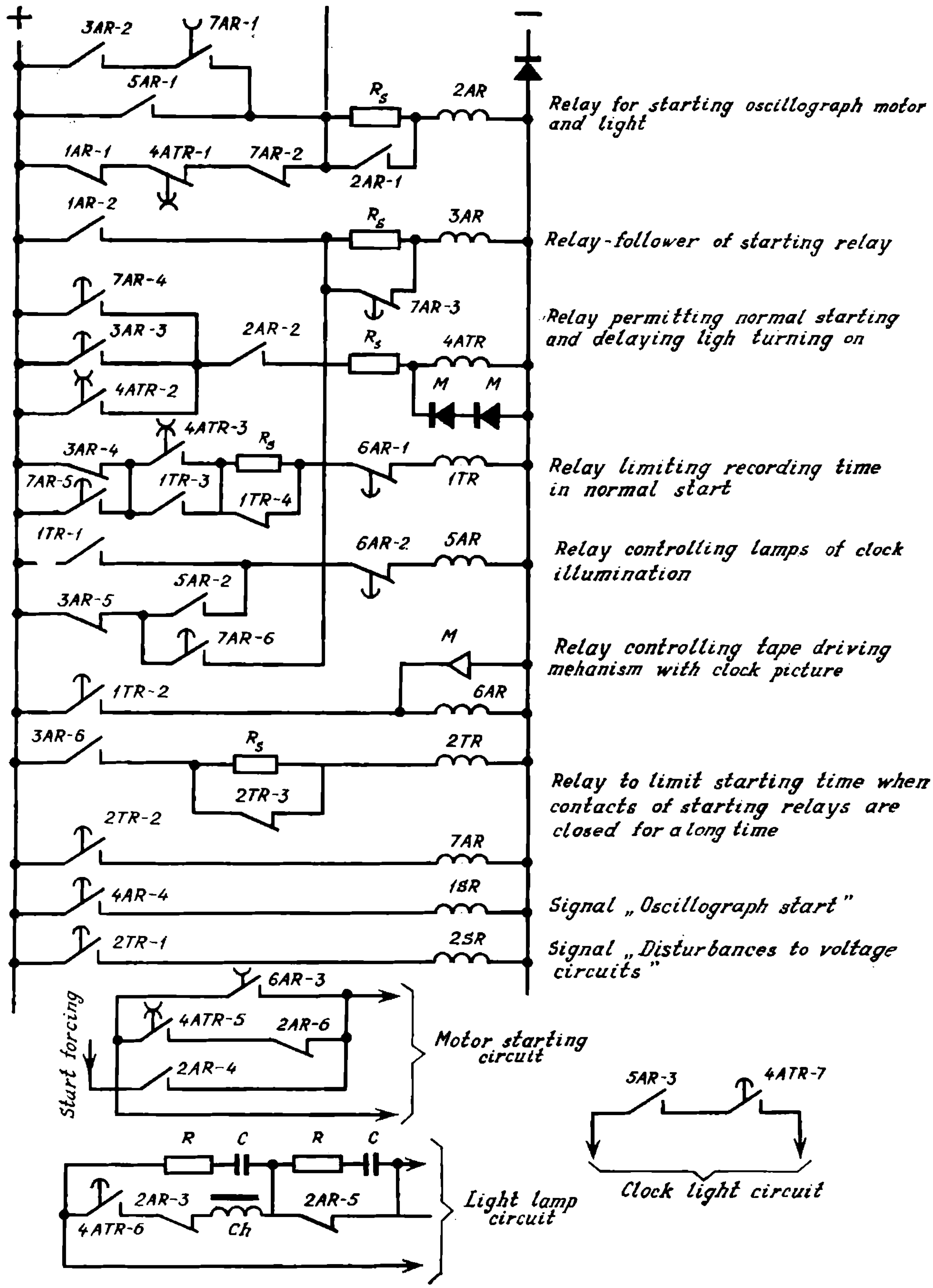


Fig. 14-4. Operating circuits of starting device for oscillographs, type УПО-1

a pickup time greater than that of relay *1TR*, functions after the operation of relay *3AR* and closure of its *3AR-6* contact. After closing the contact *2RT-2*, the relay *7AR* functions. The contact *7AR-1* closes the relay *2AR* to make the circuits for a prolonged closure of the relay *1TR* to enable the record to be completed.

14-3. Devices for Recording Electrical Variables with Automatic Acceleration of Recording Speeds During Disturbances

We now consider the recorders, models H-385, H-388 and P-335, with accelerated paper speeds during faults which are used in a number of Soviet power systems. The H-385 instrument is an ammeter or voltmeter which records

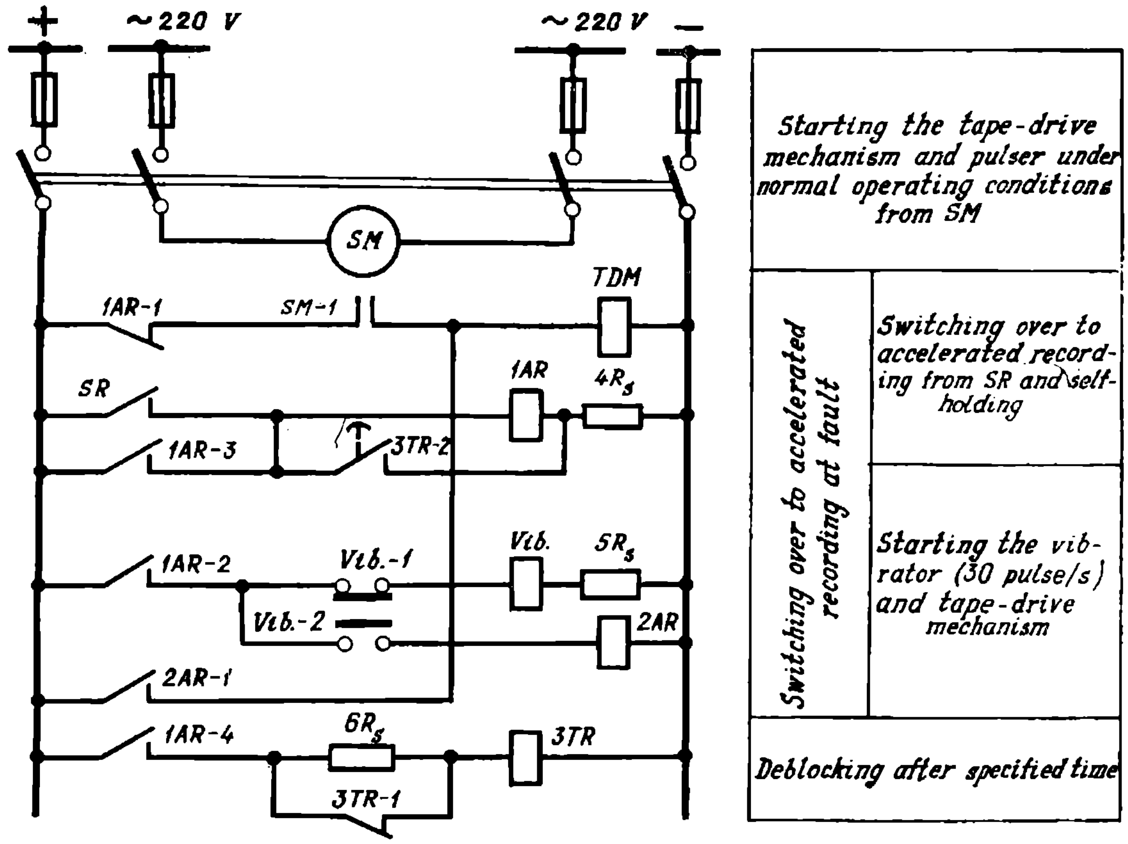


Fig. 14-5. Connection of tape-drive mechanism of recording instruments with accelerated recording speeds during faults

SM — synchronous motor; *TDM* — coil of electromagnet of tape-drive mechanism; *Vib* — coil of vibrator electromagnet; R_s — series resistor; *SR* — contact of starting relay which changes over the instrument to accelerated recording speed during fault; *1AR*, *2AR* — auxiliary relays

the variables under measurement at a paper speed of 60 mm/h under normal operating conditions and at an accelerated paper speed of 3600 mm/h under emergency conditions. The H-388 recording frequency meter has the same paper feed parameters. The P-335 tape-drive mechanism feeds the tape in

pulses. Under normal operating conditions a synchronous motor *SM* forms 180 pulses per hour, whose contact *SM-1* alternately closes the coil of the tape-drive mechanism electromagnet (Fig. 14-5)[14-4].

When recording the faulty operation, after the action of the starting relay *SR*, the auxiliary relay *1AR* functions and its contact *1AR-1* opens the circuit of the tape-drive mechanism controlled by the *SM-1* contact and its other contact *1AR-2* closes the circuit of the electromagnet coil of the vibrator. When the vibrator operates, the contact *Vib-1* opens and the contact *Vib-2* closes. The last to close is the auxiliary relay *2AR*. The circuit of the tape-drive mechanism is completed by the contact *2AR-1* oscillating in time with the vibrator (30 pulses per second).

The paper moves 0.33 mm per pulse. The pulse motor is supplied from a d.c. 48-, 110- or 220-V source. The *SM* synchronous motor operates from an a.c. 220-V source.

Each operation of the starting device, which transfers the tape-drive mechanism to accelerated operation, results in operation of the release gear and action of the paper-advance mechanism for 24 s (time relay *3TR* and auxiliary relay *1AR* are shown conventionally in Fig. 14-5 as the release gear. Relay *1AR* locks itself till the contact *3TR-2* closes).

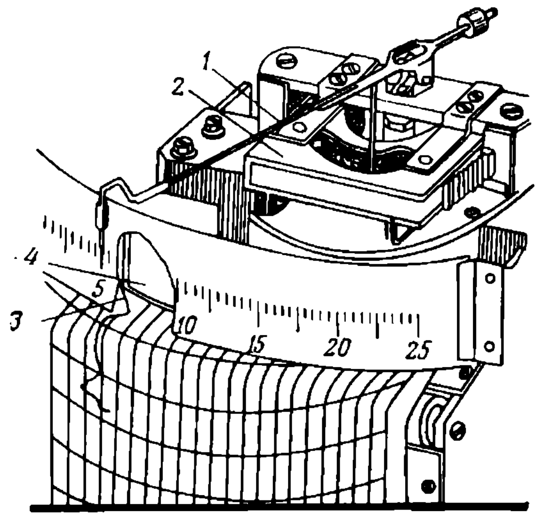


Fig. 14-6. Recorder with accelerated indication recording during faults
1 — metallic tube; *2* — ink well; *3* — glass tube capillary; *4* — chart paper strip

Another instrument model with accelerated recording speeds assures the emergency transfer to accelerated recording by deenergizing the electromagnetic coupling which is forced back by a spring and changes the gear ratio between the shafts of the synchronous motor and the tape-drive mechanism. The accelerated drive of the tape continues 12 s. If, after the 10th second, the starting relay repeats its operation, a repeated accelerated drive of the tape continues for other 12 seconds and so on. Available in this mode of operation are ammeters and voltmeters, model H-32, frequency meters, model H-33, and a transducer to supply the motor of the tape-drive mechanism P-344. The instruments are furnished with a marker which indicates the moment of transfer to the accelerated recording. The marker is an electromagnet whose armature carries the holder of a "pen" in the form of a capillary glass tube which is coupled with an ink well through a rubber tube. Under normal operating conditions the marker armature is attracted and the pen draws the starting line. In the transfer to the accelerated recording, the electromagnet circuit is deenergized and the pen draws a line lagging the starting one by 1.5 to 2 mm.

The instrument indications are recorded on chart paper (Fig. 14-6) by means of a recording device which is a metallic tube, one end of which is dipped into

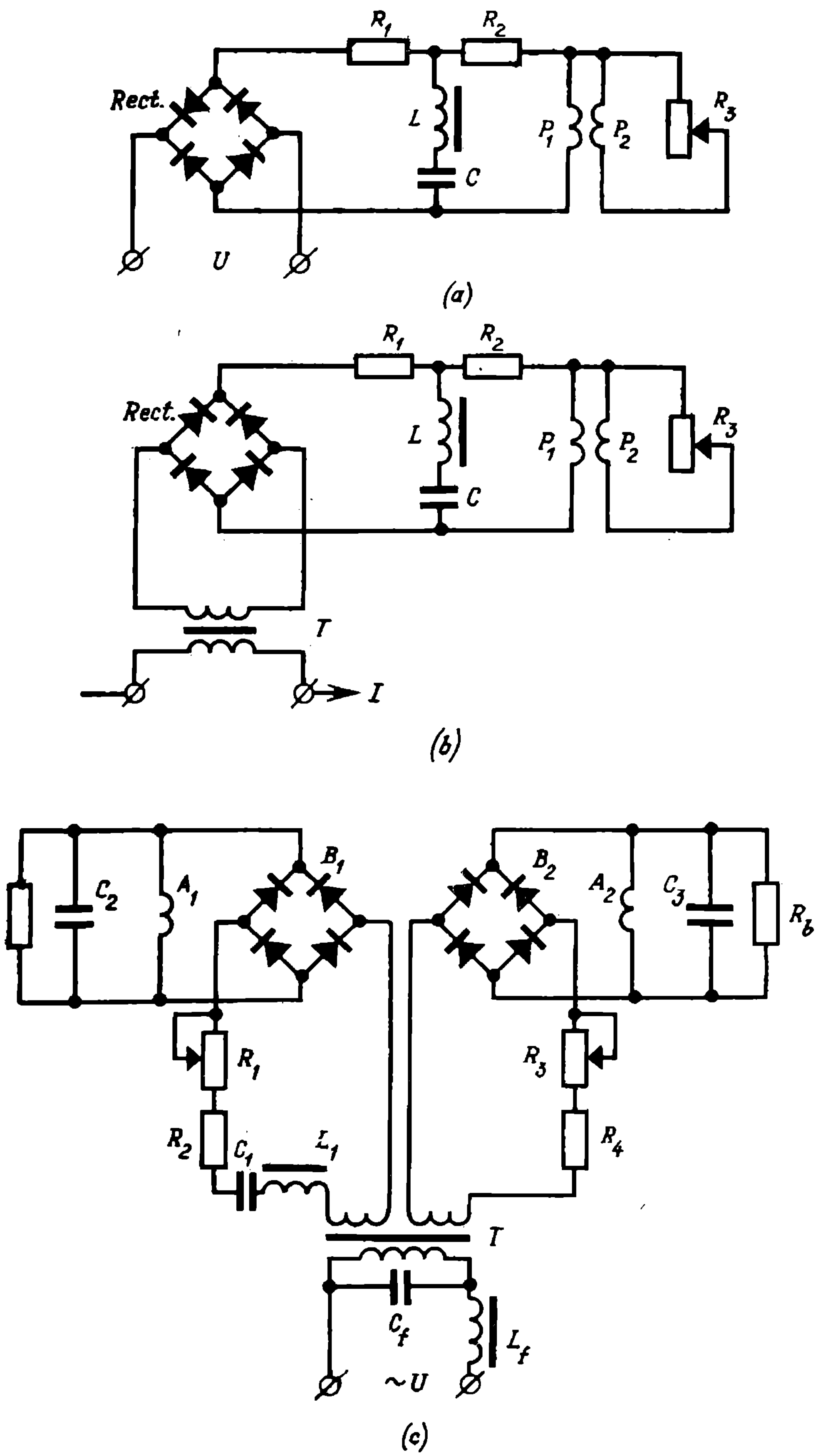


Fig. 14-7. Measuring system of instruments with accelerated recording of indications during faults

(a) voltmeter; (b) ammeter; (c) frequency meter, 45-55 Hz

an ink well. The other end has a glass capillary contacting the moving paper. A pointer is attached to the tube of the recording device.

Both, under normal and emergency operating conditions the power supply to the synchronous motor driving the chart paper is from a transducer producing a.c. power at 50 ± 0.5 Hz. Under normal operating conditions the transducer is connected to an a.c. line; under emergency conditions it is automatically transferred to the voltage of an auxiliary d.c. power source. The transducer employs semiconductor devices and is intended to supply power to four recording instruments.

Used as measuring elements are devices with moving frames connected to the rectified current (ratiometers). Shown in Fig. 14-7 is an ammeter circuit (*a*), a voltmeter circuit (*b*) and a frequency meter circuit (*c*).

14-4. Automatic Oscillographs

Let the operating principle of modern type automatic oscillographs be illustrated on an example of an automatic light-beam 12-channel oscillograph, model H-13, and an automatic magnetic oscillograph, model HO22.

(a) **Oscillograph H-13.** In this instrument the recording (oscillogram photographing) is made directly on sensitized paper tape 35, 60, 100 and 120 mm wide. The number of channels is 12. The tape-drive speed is 200 and 400 mm/s. After the faulty operation is recorded, the clock dial is photographed. The clock has three hands one of which indicates the day of the week and the others the time of day. The clock is wound up weekly. For the external view of the oscillograph and its optical system see Figs 14-8 and 14-9.

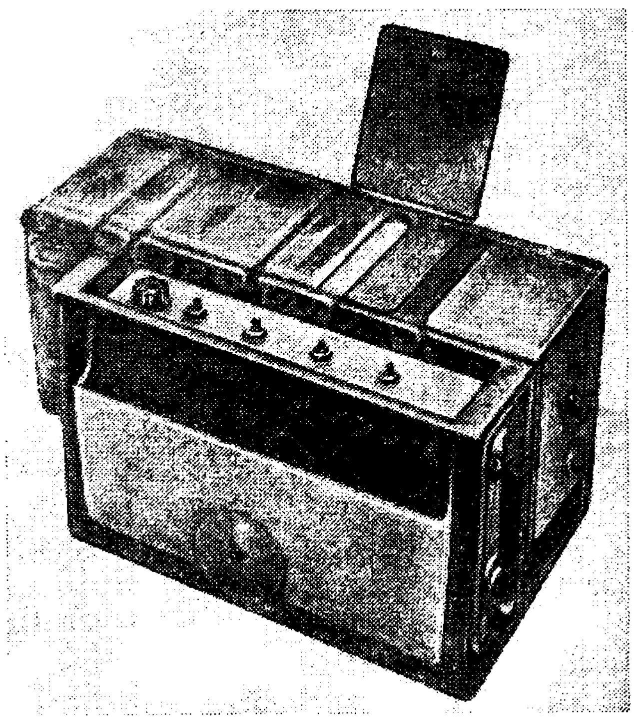


Fig. 14-8. Automatic light-beam 12-channel oscillograph, model H-13

After the action of the starting device, the optical system of oscillograph *1* is forced into operation by a capacitor discharging to the lamp filament (Fig. 14-9*a* and *b*). Next, the tape-drive mechanism is actuated for the specified time. The light beam is pinpointed by lens *2* and directed to galvanometer mirror *5* by focusing lens *4*. When reflected from the galvanometer mirror, the beam enters lense *4* and strikes mirror *7* where it divides into two rays. One impinges on mirror *8* and reflects to screen *3*, the other passes through lens *12* onto photographic paper *14*.

Mirror *6*, made of two strips, regulates the galvanometer position in the vertical plane. As this mirror turns (Fig. 14-9*b*), it reflects the split light beam to screen *3*. With the galvanometer in the mean position, a straight line of light divided in the centre by a dark strip is seen on screen *3*.

The dial of clock *11* is illuminated by light source *9* controlled by the starting device. Being reflected from the clock face the light beam is re-reflected

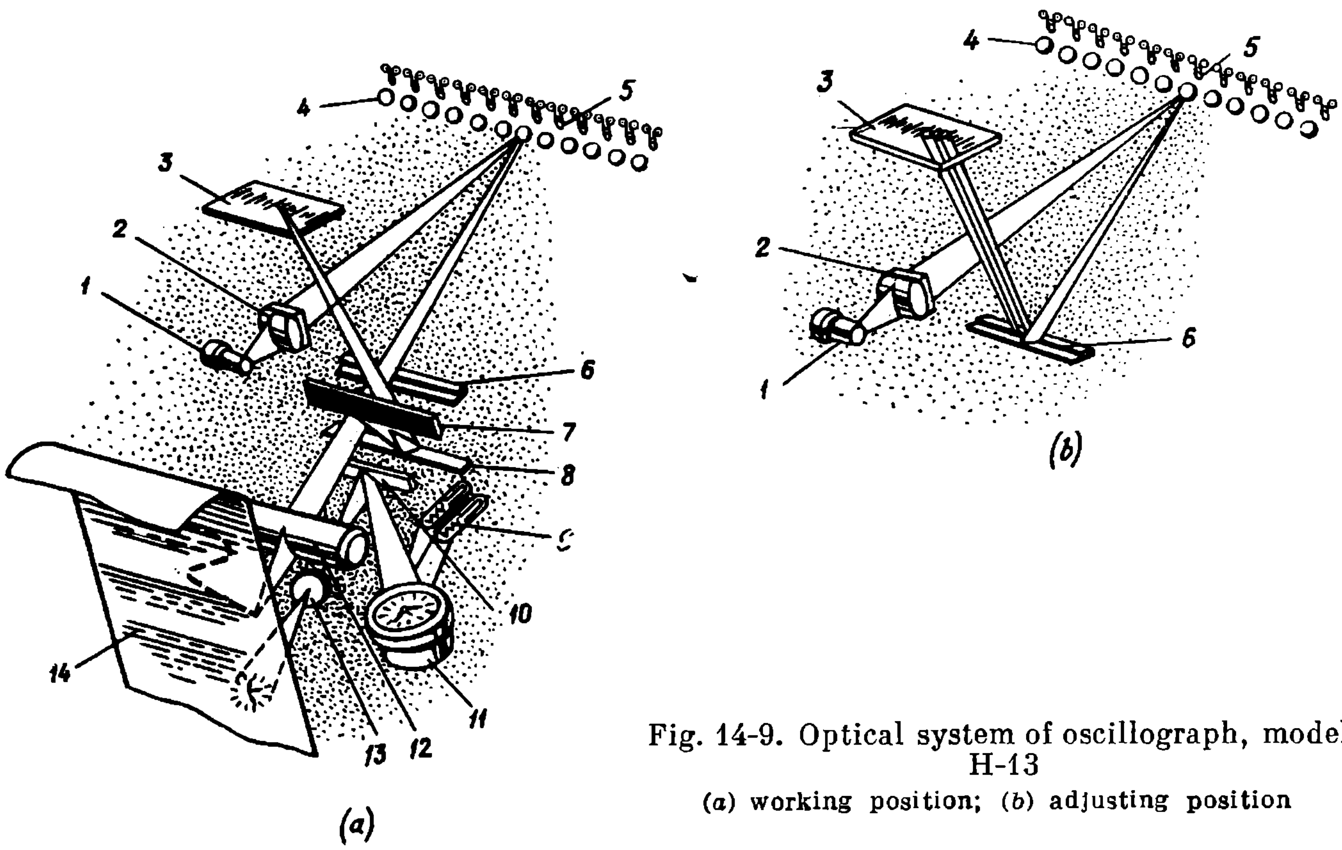


Fig. 14-9. Optical system of oscillograph, model H-13

(*a*) working position; (*b*) adjusting position

by mirror *10* to lens *13* and into the photographic paper tape below the working slit of the holder.

The oscillograph starting time from the instant of closing the starting relay contacts does not exceed 15 ms. The starting time is regulated by the setting of the starting relay after the faulty operation is recorded, the clock illumination is turned on for 1.5 s. The tape-drive mechanism operates for 0.15-0.2 s more and the clock dial picture moves into the holder slit.

Power is supplied to the oscillograph from a d.c. 110- or 220-V source through a special supply unit. When supplied from a 220-V source, the power consumption does not exceed 400 W. Dimensions are 500 × 305 × 280 mm for the oscillograph, 115 × 250 × 390 mm for the supply unit and 90 × × 330 × 485 mm for the box of shunts and series resistors.

(b) **Oscillograph HO22.** The block diagram of the oscillograph HO22 is shown in Fig. 14-10[14-3]. Through the box of shunts and series resistors *2* electrical variables *1* (current or voltage) are fed to magnetic retardation unit *3*. When there is no fault on the objects under supervision, the record is conti-

nuously erased from the magnetic drum without a preliminary recording on the photographic film. Abnormal operation causes starting device *4* to function.

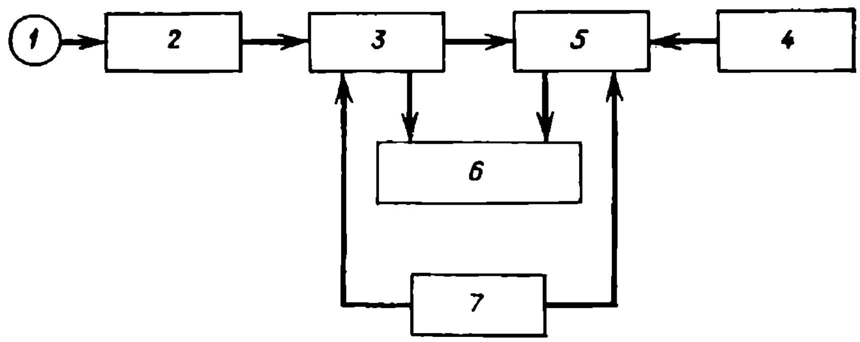


Fig. 14-10. Block diagram of oscillograph, model HO22

1 — variable to be recorded; *2* — shunt and resistor box; *3* — magnetic retardation unit; *4* — starting device; *5* — light-beam recording unit; *6* — adjustment signalling and automatic control unit; *7* — power unit

Prior to the erasing process, the film recording equipment is switched on by light-beam recording unit *5*. The electromagnetic signals of the magnetic

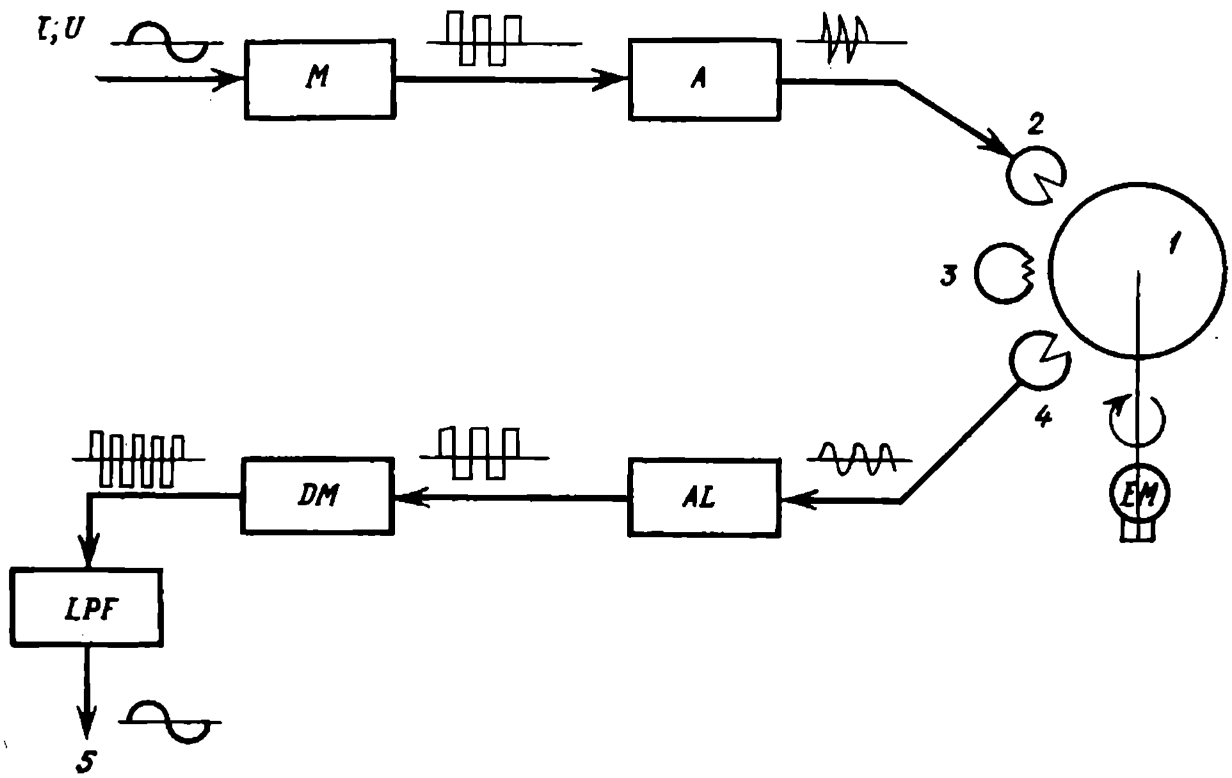


Fig. 14-11. Block diagram of magnetic recording channel

M — modulator; *A* — amplifier of recording current; *LPF* — low-pass filter; *DM* — demodulator *AL* — amplifier-limiter; *1* — magnetic drum; *2* — recording head; *3* — erasing head; *4* — reproducing head; *5* — circuit to galvanometer

retardation unit are converted into light signals in the indication, signalling and automatic unit *6*. The magnetic retardation and light-beam units are supplied from power unit *7*.

Figure 14-11 shows the block diagram of a magnetic recording channel which illustrates the operating principle. A variable (current or voltage signal) is fed to the input of modulator *M* in which the signal is converted into a series of rectangular pulses whose frequency depends on the value and polarity of the incoming signal. The signals are amplified by amplifier *A* and fed to recording head *2*. Through the magnetic drum *1* driven by electric motor *M*, as the drum completes its revolution, the recorded pulses are sent to reproducing head *4*. As drum *1* rotates, the record is erased by the erasing head of a permanent magnet. Then the process repeats.

The pulses recorded by reproducing head *4* are amplified by amplifier-limiter *AL*. Demodulator *DM* and low-pass filter *LPF* transform the pulses into a current which corresponds to the variable under measurement in shape and value. The output current of the *LPF* unit is fed to light-beam recording unit *5* (to the galvanometer loop). The process is photographed when the starting element of the oscillograph functions.

The maximum permissible operating time of the starting element is determined by the time taken by the magnetic recording drum to move from recording head *2* to reproducing head *4*. It is seen from the block diagram of the magnetic recording channel that when a fault occurs in the power system under supervision, the before-fault operation will be also recorded.

The individual units of the oscillograph HO22 are designed with the use of electronic and semiconductor devices. Study of the operation of individual units needs special training and literature (for example, reference [14-3]).

14-5. Locating the Fault on Power Transmission Line from Fixing Instruments

The position of a fault on a power transmission line may be found when the currents and voltages at the line ends are known. Records made by automatic oscillographs may be used for the purpose. However, the recorded data takes relatively much analyzing time and does not allow the dispatcher to quickly dispatch a repair team to the place of fault. That is why instruments which directly indicate the short-circuit initial current and voltage against their scale are widely used. To prevent the d.c. component in the short-circuit current affecting the measurements, the readings are fixed 2 cycles of commercial frequency after the moment the fault occurred. The fixing instruments are installed everywhere with automatic oscillographs. Their use techniques are explained below [14-5].

Let power system *I* be connected to power system *II* with power transmission line *M-N* (Fig. 14-12). An earth fault occurs at point *SC* at distances l_{Msc} and l_{Nsc} from the busbars of substations *M* and *N*, respectively. The zero-sequence impedance to point *SC* from the busbars of substation *M* is

$$z_{0Msc} = l_{Msc} z_0 \tag{14-1}$$

and from the busbars of substation *N*

$$z_{0Nsc} = l_{Ncs} z_0 \tag{14-2}$$

where z_0 is the zero-sequence impedance of a power transmission line, 1 km long.

The zero-sequence impedance of power system I is equal to z_{0M}, with reference to the busbars of substation M, and that of power system II equals z_{0N}, when corrected to the busbars of substation N.

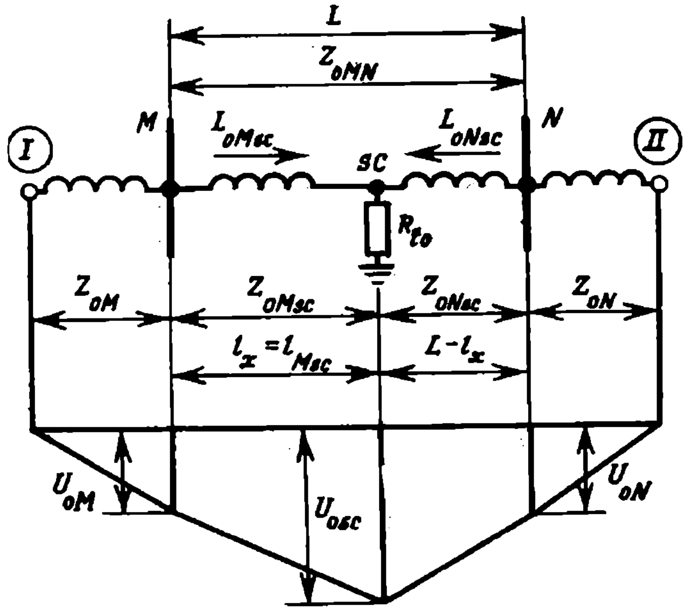


Fig. 14-12. Distribution of zero-sequence voltage along single power transmission line during one-phase short circuit (R_{t0} — transient resistance of zero-sequence)

Let the zero-sequence currents flowing to the earth fault from substation M be marked I_{0Msc} and those from substation N, I_{0Nsc}, then with emf's E_{I} and E_{II} similar in direction and value, we have

$$\frac{I_{0Msc}}{I_{0Nsc}}=\frac{z_{0Nsc}+z_{0N}}{z_{0Msc}+z_{0M}} \tag{14-3}$$

Since

$$z_{0Msc}+z_{0Nsc}=Z_{0MN} \tag{14-4}$$

while

$$\left.\begin{aligned} z_{0Msc}&=z_0 l_{Msc}=z_0 l_x \\ z_{0Nsc}&=z_0(L-l_x) \end{aligned}\right\} \tag{14-5}$$

and

then

$$\frac{I_{0Msc}}{I_{0Nsc}}=\frac{z_0(L-l_x)+z_{0N}}{z_0 l_x+z_{0M}} \tag{14-6}$$

After denoting

$$\alpha_0=\frac{I_{0Msc}}{I_{0Nsc}} \tag{14-7}$$

and replacing the complex value of impedances with their absolute magnitudes, we may approximately write

$$\alpha_0 z_0 l_x + \alpha_0 z_{0M} = z_0 L - z_0 l_x + z_{0N}$$

$$l_x z_0 (\alpha_0 + 1) = (z_{0N} - z_{0M}\alpha_0) + z_0 L$$

hence

$$l_x = \frac{(z_{0N} - \alpha_0 z_{0M}) + z_0 L}{z_0 (\alpha_0 + 1)} \tag{14-8}$$

where l_x = distance from the busbars of substation M to earth fault SC

L = length of the power transmission line between substations M and N

z_0 = zero-sequence impedance of 1 km of power transmission line

It follows from (14-3) that the transient resistance R_{t0} need not be known in order to determine the distance to the earth fault by (14-8), but it is necessary to preliminary calculate the z_{0M} and z_{0N} impedances and determine the value of α_0 against the scale readings of the measuring instruments.

To ease the work of load dispatching personnel, the values of z_{0M} and z_{0N} are calculated earlier for various operating conditions with reference to the different substations of the tie link. It follows from (14-8) that in order to determine l_x the length L of the M to N section should be known.

The fault point may be also found from the readings of the instrument measuring the zero-sequence voltage across the busbars of substations M and N.

From Fig. 14-12 it follows that

$$\left.\begin{aligned} \frac{U_{0sc}}{U_{0M}} &= \frac{z_{0M} + z_{0Msc}}{z_{0M}} \\ \text{and} \quad & \\ \frac{U_{0sc}}{U_{0N}} &= \frac{z_{0N} + z_{0Nsc}}{z_{0N}} \end{aligned}\right\} \tag{14-9}$$

or

$$\beta_0 = \frac{U_{0M}}{U_{0N}} = \frac{z_{0N} + z_{0Nsc}}{z_{0M} + z_{0Msc}} \cdot \frac{z_{0M}}{z_{0N}} \tag{14-10}$$

Taking into account (14-5) and substituting the absolute values for the complex values of impedances, we have

$$\beta_0 z_{0N} [z_{0M} + z_0 l_x] = z_{0M} [z_{0N} + z_0 (L - l_x)]$$

$$z_0 l_x (\beta_0 z_{0N} + z_{0M}) = z_{0M} z_{0N} (1 - \beta_0) + z_0 z_{0M} L$$

or

$$l_x = \frac{z_{0M} z_{0N} (1 - \beta_0) + z_0 z_{0M} L}{z_0 (\beta_0 z_{0N} + z_{0M})} \tag{14-11}$$

If the quantities U_{0M}, U_{0N}, I_{0Msc} and I_{0Nsc} are measured, then the place of fault may be determined without the preliminary calculations of impedances z_{0M} and z_{0N} which are not constant and whose values greatly depend upon the operating conditions of power systems I and II.

It follows from Fig. 14-12, that the zero-sequence voltage at the SC fault point

$$U_{0sc} = U_{0M} + I_{0Msc} l_x z_0 = U_{0N} + I_{0Nsc} z_0 (L - l_x)$$

hence

$$z_0 l_x (I_{0Msc} + I_{0Nsc}) = (U_{0N} - U_{0M}) + I_{0Nsc} z_0 L$$

and

$$l_x = \frac{(U_{0N} - U_{0M}) + I_{0Nsc} z_0 L}{z_0 (I_{0Msc} + I_{0Nsc})} \tag{14-12}$$

Expressions (14-8), (14-11) and (14-12) are suitable for locating the place of fault on single power transmission lines. When a parallel line is present, use may be made of (14-12) if the mutual inductance effect is included into the zero-sequence impedance and the circuit of the parallel lines is converted into an equivalent star circuit [14-6]. In such instances, it is more simple to determine the zero-sequence current and voltage in order to locate the place of fault by a relation similar to (14-12), Fig. 14-13.

To help the load dispatching personnel, sometimes special nomograms are used, these speed up the fault location calculations. The principle of the nomogram construction for instances when the power transmission line is furnished at the ends with fixing ammeters connected to the zero-sequence current is now explained.

When an earth fault occurs on one or two phases, we can write in compliance with Figs 14-12 and 14-14 that

$$I_{0sc} = I_{0Msc} + I_{0Nsc} \tag{14-13}$$

and

$$\frac{I_{0Msc}}{I_{0Nsc}} = \frac{z_0 l_y + z_{0N}}{z_0 l_x + z_{0M}} \tag{14-14}$$

Let expression (14-14) be transformed as follows

$$\frac{I_{0Msc} + I_{0Nsc}}{I_{0Nsc}} = \frac{z_0 l_y + z_{0N} + z_0 l_x + z_{0M}}{z_0 l_x + z_{0M}}$$

or

$$\frac{I_{0sc}}{I_{0Nsc}} = \frac{z_{0M} + z_{0N} + z_0 L}{z_0 l_x + z_{0M}} = \frac{z_{0\,(\mathrm{I\text{-}II})}}{z_0 l_x + z_{0M}} \tag{14-15}$$

Let

$$\xi_0 = \frac{I_{0Nsc}}{I_{0sc}} = \frac{3I_{0Nsc}}{3I_{0Msc} + 3I_{0Nsc}} \tag{14-16}$$

Expression (14-15) with account of (14-16) may be presented as

$$\xi_0 = \frac{z_0}{z_{0\,(\mathrm{I\text{-}II})}} l_x + \frac{z_{0M}}{z_{0\,(\mathrm{I\text{-}II})}} \tag{14-17}$$

The distance to the place of fault (to point SC) from substation M (kilometers)

$$l_x = \xi_0 \frac{z_{0\,(\mathrm{I\text{-}II})}}{z_0} - \frac{z_{0M}}{z_0} \tag{14-18}$$

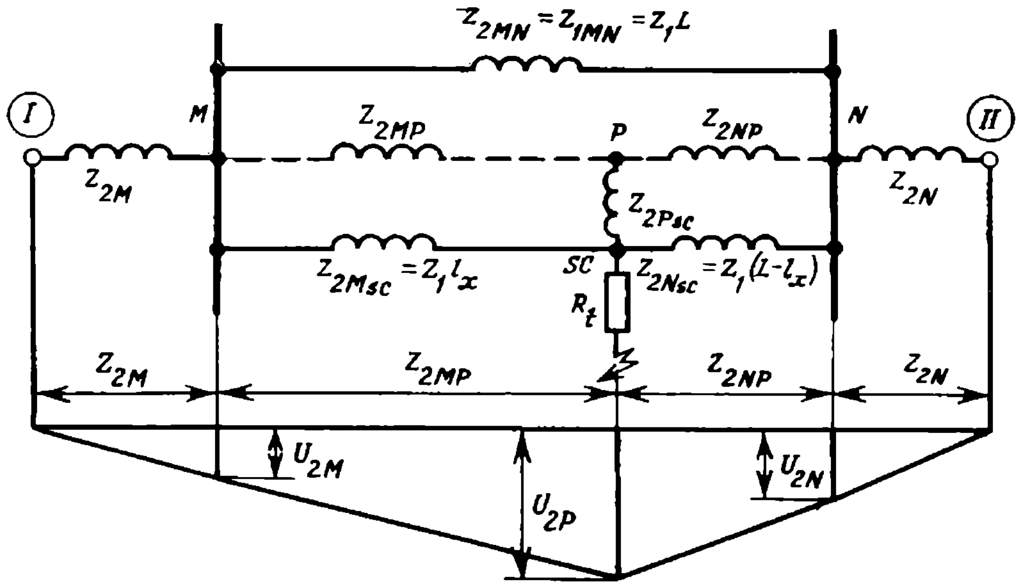


Fig. 14-13. Distribution of backward-sequence voltage during asymmetric short circuit (shown in broken line is equivalent circuit for converting delta connection into star connection

$$z_{2MP}=\frac{z_{2Msc}}{2};\quad v_{2NP}=\frac{z_{2Nsc}}{2}\ \text{and}\ z_{2Psc}=\frac{z_{2Msc}z_{2Nsc}}{z_{2MN}+z_{2Msc}+z_{2Msc}}$$

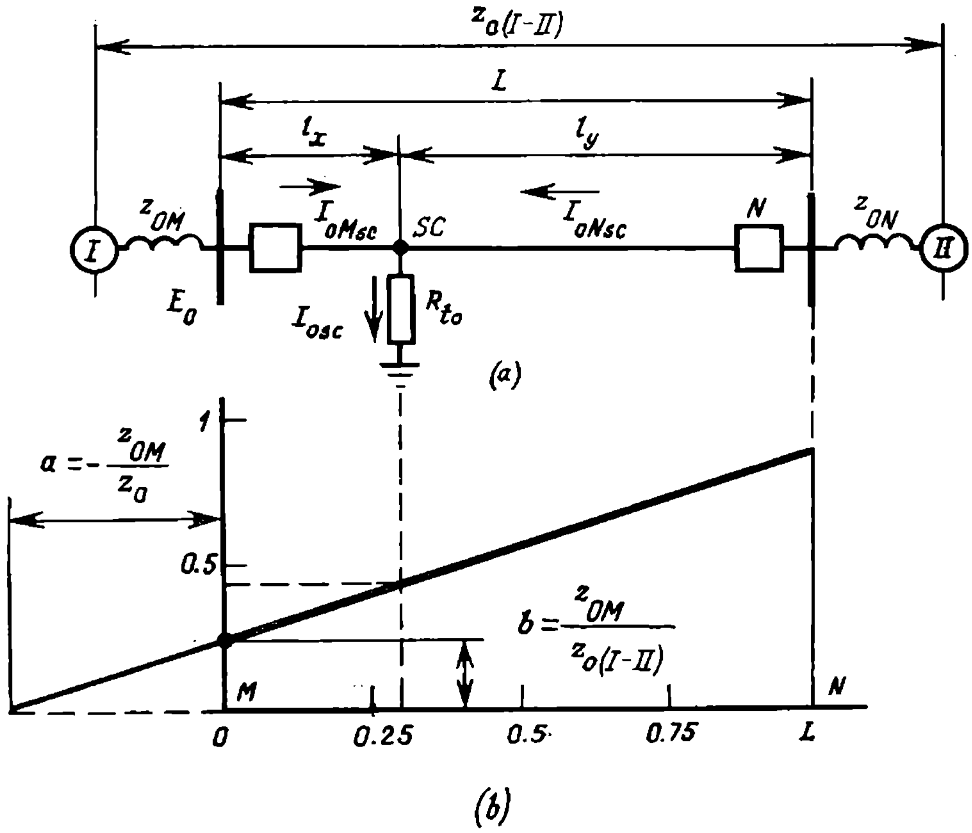


Fig. 14-14. Nomogram for locating earth fault by means o data obtained by simultaneously measuring $3I_0$ currents from both ends of the power transmission line

(*a*) explanatory diagram; (*b*) nomogram

Equating in (14-18) first the value of ξ_0 and then the value of l_x to zero, it becomes easy to determine the variables a and b for constructing the nomogram (Fig. 14-14*b*). In the above expressions, the mutual zero-sequence impedance $z_{0(\text{I-II})}$ between the neutral points of power systems *I* and *II* must be given in ohms.

The relationship $l_x = f(\xi_0)$ is a rectilinear one.

The ratios $z_{0(\text{I-II})}/z_0$ and z_{0M}/z_0 vary with the operating conditions of the power systems, but in each case the variations are quite definite and the load dispatcher has no difficulty in determining distance l_x when he knows the before-fault condition (the circuit configuration) and receives reports from the duty personnel at substations *M* and *N*.

When the backward-sequence currents are fixed the nomogram has a form similar to those shown in Fig. 14-14*b*, and the calculating expression is similar to (14-18) but with the replacement of the zero-sequence variables with backward-sequence variables.

When the service is supervised by a load dispatcher, he must know the types of the instruments installed at the substations, the electrical variables the instruments respond to, and how to perform the calculations. It is important that the substation and power station operators read correctly and report the currents and voltages registered by the fixing instruments to the load dispatcher and reset the fixing instruments before the power transmission line is reenergized.

Since load control departments are now being equipped with electronic computers, the further development of fixing instruments must be combined with the use of computers, i.e., the fixing instrument readings must be telecommunicated to the computing centre so that the machines "memory" is utilized for entry of data characterizing the before-fault operation (for example, the zero- and backward-sequence impedances with reference to the busbars of substations *M* and *N*) into the programming expression.

14-6. Fixing Instruments

A number of power systems have developed fixing instruments of different types. Basically there are two different types. In the first the instrument readings are fixed by the pointer being pressed down. The pressing device operates soon after the occurrence of a short circuit so that enough time for the damping of the pointer and decaying of the d.c. component of the short-circuit current is provided. In the second type a capacitor is charged a short time after the occurrence of a short-circuit (0.06 to 0.1 s) in proportion to the current or voltage under measurement. The capacitor then discharges into an indicator whose reading is thus governed by the value of the current or voltage being measured.

A fixing ammeter is shown in Fig. 14-15. When a one-phase short circuit occurs, a current appears in the instrument and makes a starting relay (Fig. 14-16) function. Then, the *1ATR* relay having the operating time of 0.07 s closes. The relay holds itself closed by its contact *1ATR-1* and its contact *1ATR-2*

closes auxiliary relay *2AR* which presses down the pointer. A signal is given by contact *1ATR-3*. Resistor *1R* is placed into the $3I_0$ current circuit. The voltage drop across this resistor is proportional to the I_0 current. This is measured by the indicator. The supply to the indicator loop is from the circuit shown in Fig. 14-16*b* which incorporates a 600-μF capacitor bypassing the

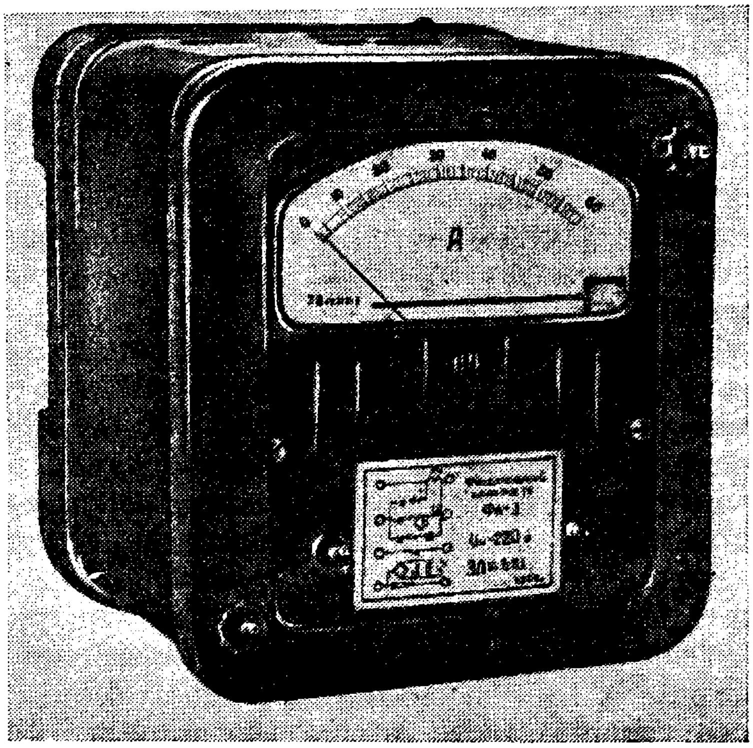


Fig. 14-15. Fixing ammeter, model ФА-3

loop. This measure along with an increase in the return spring torque ensures the dead-beat movement of the pointer. The device is reset by operating push-button *B* (Fig. 14-16*a*).

Instead of instruments with a locking pointer mechanism sometimes a millicoulometer is used. The latter has no reactionary torque and the pointer, possessing large overdamping, when once deflected through some angle, remains in this position until acted upon by another return pulse.

For the connection diagram see Fig. 14-17.

The moment a short circuit occurs, the current relay *CR* functions and its contact *CR-1* opens the secondary winding of the intervening current transformer *T* to allow the capacitor *C* to charge. The contact *CR-2* closes the auxiliary relay *ATR* whose pickup is delayed for about 60 mc. The relay *ATR* by contact *ATR-1* holds itself closed, contact *ATR-2* completes the signalling circuit, while contacts *ATR-3* and *ATR-4* switch over the capacitor *C* from a rectifier to the millicoulometer. The instrument pointer deflection is proportional to the current in the circuit.

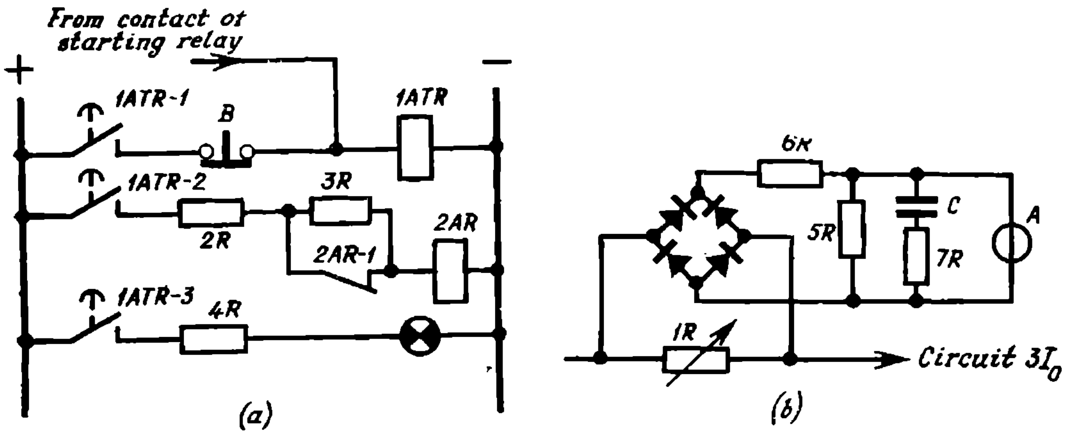


Fig. 14-16. Connection of fixing ammeter ФА-3

1ATR — auxiliary relay delayed in pickup for 0.07 s; *2AR* — relay of pressing device; *R* — resistor (*1R* — bypassing adjusting resistor; *2R* = 3 kOhm; *3R* = 4 kOhm; *4R* = = 25 kOhm; *5R* = 300-600 Ohm; *6R* = 25-50 Ohm; *7R*=0-30 Ohm); *C* — capacitor, 600 μF; *A* — ammeter, range 0-100 μA, loop resistance of 650-800 Ohm; *B* — button

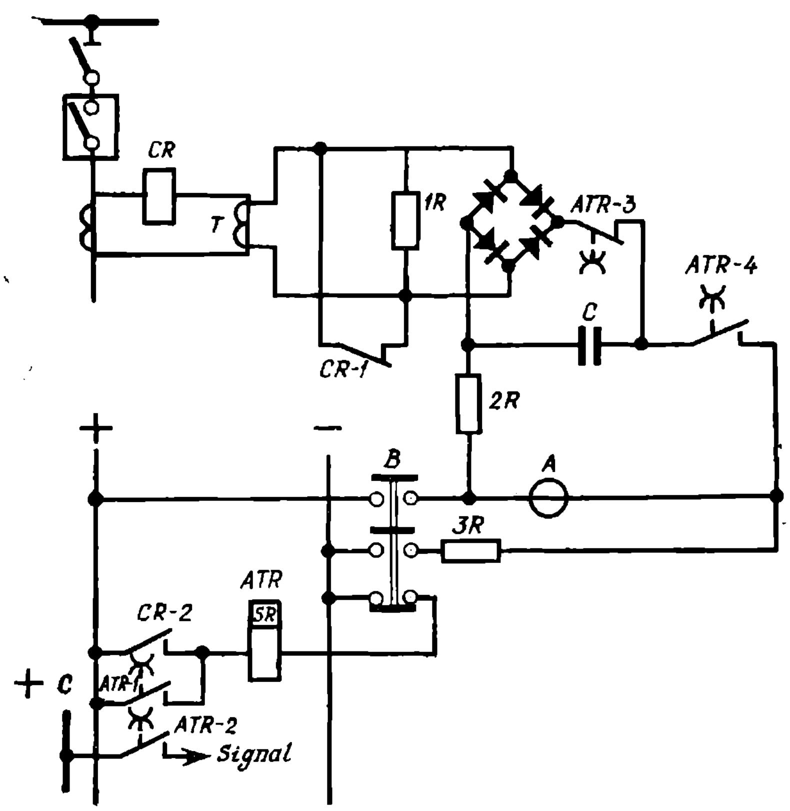


Fig. 14-17. Connection of millicoulometer to fix the starting value of short-circuit current

CR — current relay; *R* — series resistor (*1R* = 70 Ohm; *2R* = 4000 Ohm; *3R* = 60,000 Ohm at operating voltage of 220 V). *ATR* — auxiliary relay delayed in pickup for 60 ms; *A* — millicoulometer; *C* — capacitor, 20 μF; *T* — intervening transformer; *B* — button

After the instrument readings are recorded, the instrument is reset by pressing the push-button *B*, one contact of which opens the self-holding circuit of relay *ATR*. The other two contacts of this relay switch over the measuring

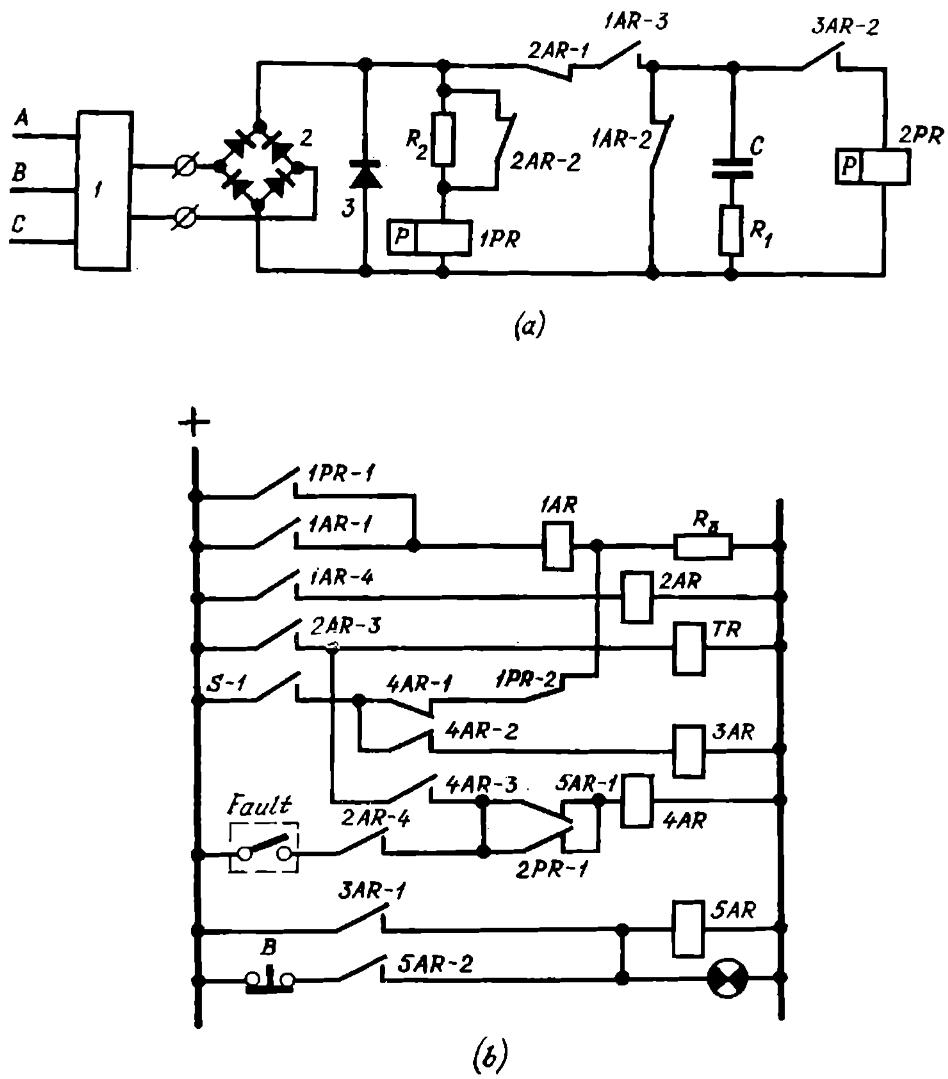


Fig. 14-18. Automatic instrument for measuring voltage at fault

(*a*) a.c. and rectified current voltage circuits; (*b*) d.c. circuits; *1* — filter of zero- or backward-sequence voltage; *2* — rectifier bridge; *3* — rectifier; *1PR* and *2PR* — polarized relays; *1AR* through *5AR* — auxiliary relays; *TR* — time relays; "fault"— contacts to indicate fault tripping of the line of given substation; R_1 and R_2 series resistors; *C* — capacitor; *B* — button; *L* — pilot lamp

instrument to the operating power source. This switching is performed at reverse polarity to set the pointer to zero.

A voltage measurement circuit of a fixing instrument is shown in Fig. 14-18. When a short circuit occurs, the voltage developed across the zero- or backward-sequence filter appears at the input of the automatic instrument. The voltage is rectified and applied to the starting polarized relay *1PR* which functions and completes the coil circuit of auxiliary relay *1AR*.

The relay *1AR* holds itself closed by contact *1AR-1*. Its contact *1AR-2* opens the circuit bypassing capacitor *C*, contact *1AR-3* connects capacitor *C* to the charging circuit and contact *1AR-4* closes the coil circuit of relay *2AR* which functions and contact *2AR-1* opens the capacitor charging circuit. Simultaneously its contact *2AR-3* closes the time relay *TR* and its contact *2AR-4* prepares the circuit for closing the relay *4AR*.

If the short circuit was on lines other than those run from the busbars of the given substation, the contacts "fault" remain open and the relay *4AR* does

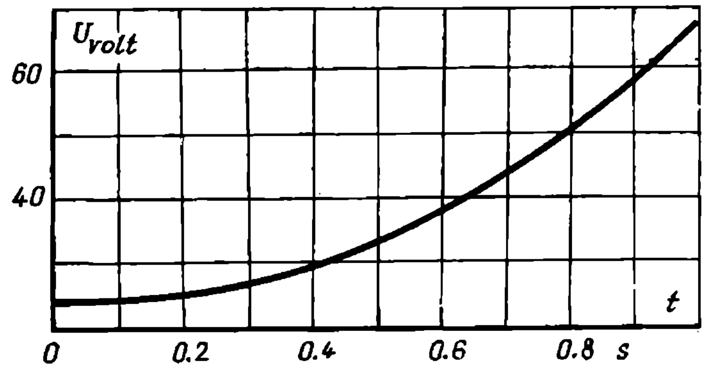


Fig. 14-19. Approximate characteristic of fault voltage measuring device

not function. The automatic instrument is released after the operation of time relay *TR* and reset of relay *1AR*. Capacitor *C* discharges. The contacts "fault" are actuated by the fault signalling device.

After the contact *TR-1* has closed, the relay *3AR* picks up through the circuit *S-1—4AR-2—3AR*. The contact *3AR-2* connects the capacitor so that it discharges through the coil of polarized relay *2PR* and the contact *3AR-1* closes the coil of auxiliary relay *5AR* which functions and opens contact *5AR-1* in the coil circuit of relay *4AR*. The coil of relay *4AR*, however, continues to carry the current until the contact of polarized relay *2PR-1* remains closed.

After the capacitor *C* has discharged, the contact *2PR-1* opens the coil circuit of relay *4AR*, whose contacts open the coil circuit of relay *3AR* and close the circuit formed by *S-1*, *4AR-1*, *1PR-2*, R_3. The coil of relay *1AR* is bypassed and, as mentioned above, the automatic instrument is reset.

To prevent repeated operation of the automatic instrument when the voltage circuits are at fault, the breaking contact *1RP-2* is inserted into the releasing circuit.

The electrical timer is controlled by the breaking contacts of relays *4AR* and *5AR* (not shown in the figure). The operating time of the timer is dependent on the time during which the capacitor discharges into the polarized relay *2PR*. This discharging time is proportional to the capacitor charge, i.e., to the value of the applied voltage. Therefore, the timer readings may be calibrated in voltage units, this is shown in Fig. 14-19.

The operating principle of the commercially available fixing instruments (fixing pulse instrument, type ФИП-1) is illustrated in Fig. 14-20 [14-7,14-8]. The three basic units in the instrument are: the volatile memory unit *VMU*, the reading unit *RU* and the reproducing unit *Rep.*

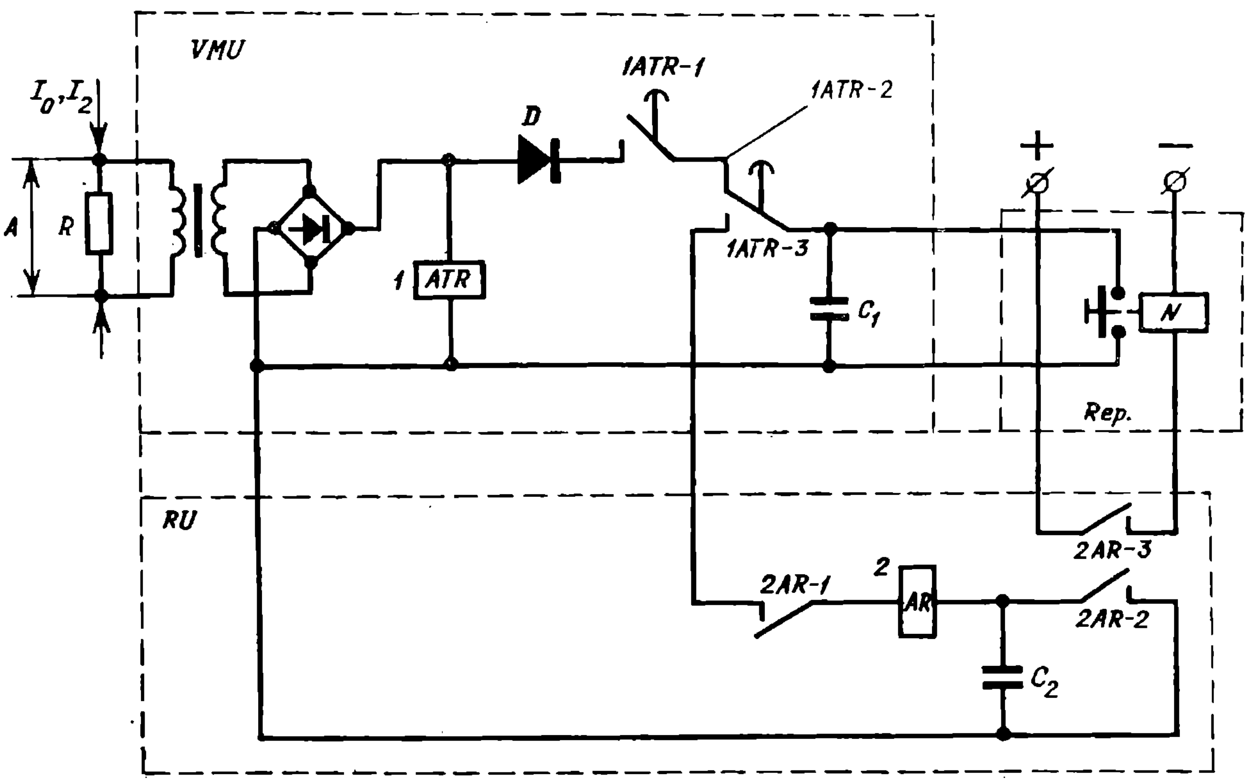


Fig. 14-20. Diagram explaining operating principle of fixing instrument, model ФИП-1

VMU — volatile memory unit; *RU* — reading unit; *Rep* — reproducing unit; t_{1ATR-1} is about 0.04 s; t_{1ATR-2} is about 0.09 s; t_{1ATR-3} is about 0.1 s

The volatile memory unit. The magnitude A being measured (for example, a voltage drop across a resistor R due to the zero-sequence current flow $3I_0$) through an intervening transformer T and rectifying bridge is fed to the *1ATR* programming device, 0.04 s later contact *1ATR-1* connects capacitor C_1 to the rectifying bridge. The capacitor charges in about 0.05 s, i.e., until the contact *1ATR-2* closes (its breaking setting is 0.09 s). Contact *1ATR-3* switches over capacitor C_1 to the circuits of the reading unit *RU*.

Reading unit. The discharge of capacitor C_1 causes a current to flow through contact *2AR-1*, the coil of relay *2AR*, and capacitor C_2, this causes relay *2AR-2* to function. Next, contacts *2AR-1* open and contacts *2AR-2* and *2AR-3* close, contact *2AR-2* completely discharges capacitor C_2, while contact *2AR-3* closes the circuit of pulse counter N of the reproduction unit. Relay *2AR* resets and reconnects to the circuit of capacitor C_1. The relay *2AR* repeatedly functions if the current produced by the charge of capacitor C_1 carried by the circuit, including the contact *2AR-1*, the coil of relay *2AR* and capacitor C_2, is greater

than the pickup current of relay *2AR*. The second pulse is fed to the pulse counter N. The process is repeated until the relay *2AR* functions under the action of the discharge current of capacitor C_1.

Reproduction unit. This unit contains pulse counter N. The pulse counter indications (i.e., the number of pulse registered) depends on the value of the charging current of capacitor C_1. This value, in its turn, is determined by the magnitude of variable A being measured.

The counter is reset for further operation by pressing the button B whose contacts short circuit capacitor C_1.

When the instruments are built commercially the *1ATR* programming device is made of high-speed polarized relays delayed through the use of *R-C* networks. Diode D prevents capacitor C_1 from discharging to the load of the rectifying bridge when the duration of the signal A under measurement is less than 0.09 s. The reproduction unit is completely transistorized [14-7].

During the reading process the voltage across the capacitor C_1 is in proportion to the variable A

$$U_C = kA \tag{14-19}$$

where k is the proportionality factor.

When capacitor C_1 is connected to capacitor C_2 for the first time, the voltage across both capacitors decreases to

$$U_1 = \frac{C_1}{C_1 + C_2} \cdot kA \tag{14-20}$$

When it is connected for the second time the voltage across both capacitors

$$U_2 = \left(\frac{C_1}{C_1 + C_2}\right)^2 \cdot kA \tag{14-21}$$

In the nth connection, when the relay *2AR* stops functioning and the voltage across the capacitors is equal to the threshold value U_{thr}, we have

$$U_N = U_{thr} = \left(\frac{C_1}{C_1 + C_2}\right)^N \cdot kA \tag{14-22}$$

It follows from (14-22) that

$$\frac{kA}{U_{thr}} = \left(\frac{C_1 + C_2}{C_1}\right)^N = \left(1 + \frac{C_2}{C_1}\right)^N$$

Hence

$$N \ln\left(1 + \frac{C_2}{C_1}\right) = \ln A + \ln \frac{k}{U_{thr}} \tag{14-23}$$

Since

$$\frac{1}{\ln\left(1 + \frac{C_2}{C_1}\right)} \approx \frac{1}{(C_2/C_1)} = \frac{C_1}{C_2} = k_C \tag{14-24}$$

then

$$N = k_C \left[\ln A + \ln \frac{k}{U_{thr}}\right] \tag{14-25}$$

The A value when $N = 0$

$$A_{N=0} = \frac{U_{thr}}{k}$$

Thus, when plotted to a semilogarithmic scale, the relation $N = f(A)$ forms a straight line (Fig. 14-21).

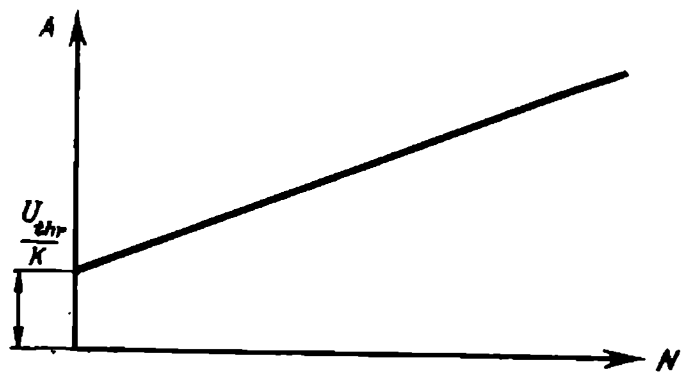


Fig. 14-21. Semilogarithmic calibration characteristic of ФИП-1 device

From (14-25) it is seen that the important advantage of this type of instrument is that the straight line does not change as the capacitance of C_1 and C_2 vary proportionally, i.e., the instrument readings are not affected by ageing of the same type capacitors.

14-7. Conclusions

1. Automatic high-speed recording of the electrical processes resulting from faults makes analysis of the operating conditions and actions of automatic devices possible. The use of recording instruments and automatic oscillographs is a prerequisite of a properly organized power supply service.
2. The recording instruments with accelerated paper speeds during faults in the power system are the most simple ones to use.
3. The automatic oscillographs commercially available have automatic starting devices to economize on photographic paper and fix the starting time.
4. The use of multichannel oscillographs enables changes in the currents carried by the various connections and of different sequences to be fixed. It is also possible to record the voltages of different sequencies and determine the sequence of operation when some elements of the automatic devices are at fault, a fact of utmost importance during the analyses of the operation of high-frequency differential phase protection.
5. Automatic devices, fixing the starting values (0.04 s from the instant a fault occurs) of the backward- and zero-sequence currents and voltages, facilitate servicing as the fault is readily located along the power transmission line.

14-8. Review Questions

1. What is the difference between the operation of an automatic oscillograph and that of a recording instrument with accelerated paper speeds during faults?
2. Under what conditions and by what methods are the automatic oscillographs started when a fault occurs? Explain why various starting procedures are used.
3. How is the photographic film saved in the film-type automatic oscillographs when lightning arresters operate during storms?
4. After a short circuit is cleared, the process under supervision continues to be recorded by the automatic oscillographs for some time. What is the purpose of this? What is the approximate stop delay time of the oscillograph?
5. Explain the purpose of the camera attachment.
6. How can electrical variables be recorded before a fault?
7. Explain the purpose of devices which fix the values of current and voltage when a short circuit occurs.
8. May an oscillogram produced by an automatic oscillograph be used in place of the readings from instruments fixing the currents and voltages resulting from short circuits?
9. Why are the currents and voltages recorded in the fixing instruments 0.04 s after the occurrence of a short circuit?
10. What are the methods underlying the operation of fixing instruments?
11. What electrical measurements should be taken in order to locate a one-phase short circuit on a single power transmission line supplied at both ends and to exclude the influence of the transient resistance and arc at the point of fault?
12. By what method are recording instruments transferred to accelerated recording?
13. To record the character of changes in the real power at faults and in the after-fault operation of the power system, the input of the oscillograph is fed from the so-called "power transducer" in which the real power is transformed into a d.c. component. May a magnetic power transducer be used for the purpose (see Section 6-7)?
14. Provision is made in the oscillograph starting device, type УПО-1, to limit the oscillograph operating time and save photographic paper (film) when a fuse blows or a circuit breaker trips in the circuits carrying the voltage being recorded. How is this action accomplished?

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